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CONSULTANT REPORT

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The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions and funded by the California Energy Commission, Public Interest Energy Research Program through the University of California, California Institute for Energy and the Environment under Contract No. 500-99-013 and by the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

PREFACE

The U.S. electric power system is in the midst of a fundamental transition from a centrally planned and utility-controlled structure to one that will depend on competitive market forces for investment, operations, and reliability management. Electric system operators are being challenged to maintain reliability levels needed for the digital economy in the face of changing industry structure and evolving market rules. The economic growth of the Nation is tied ever closer to the availability of reliable electric service. New technologies are needed to prevent major grid outages as experienced in the Western grid on August 10, 1996, which left 12 million customers without electricity for up to 8 hours and cost an estimated $2 billion.

The Consortium for Electric Reliability Technology Solutions (CERTS) was formed in 1999 to research, develop, and disseminate new methods, tools, and technologies to protect and enhance the reliability of the U.S. electric power system in the transition to a competitive electricity market structure.

CERTS is conducting public-interest electricity reliability research in four areas:

- Real-Time Grid Operations and Reliability Management
- Reliability and Markets
- Distributed Energy Resources Integration
- Reliability Technology Issues and Needs Assessment

What follows is the final report for the Transmission-Planning Research &Development Scoping Project conducted by the Consortium for Electric Reliability Technology Solutions. The report is entitled Transmission-Planning Research &Development Scoping Project. This project contributes to the Transmission Research Program Energy System Integration program.

For more information on the PIER Program, please visit the Commission's Web site http://www.energy.ca.gov/pier/reports.html or contract the Commission at (916) 654-4628.

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Transmission-Planning Research &Development
Scoping Project

Prepared for the
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Energy System Integration
Public Interest Energy Research
California Energy Commission

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Abstract

The objective of this Public Interest Energy Research (PIER) scoping project is to identify options for public-interest research and development (R&D) to improve transmission-planning tools, techniques, and methods. The information presented was gathered through a review of current California utility, California Independent System Operator (ISO), and related western states electricity transmission-planning activities and emerging needs. This report presents the project team's findings organized under six topic areas and identifies 17 distinct R&D activities to improve transmission-planning in California and the West. The findings in this report are intended for use, along with other materials, by PIER staff, to facilitate discussions with stakeholders that will ultimately lead to development of a portfolio of transmission-planning R&D activities for the PIER program.

Acknowledgments

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Acronyms and Abbreviations

AC	Alternating current
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CATS	Central Arizona Transmission Study
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CPNC	Certificate of Public Need and Convenience
CPUC	California Public Utilities Commission
CREPC	Committee on Regional Electric Power Cooperation
CRT	Colorado River Transmission
DC	Direct current
DSM	Demand-side management
EHV	Extra high voltage
ESI	Energy Systems Integration
FACTS	Flexible AC Transmission Systems
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information Systems
HHI	Herfindahl-Hirschman Index
IEC	International Electrotechnical Commission
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-owned utility
IPP	Independent power producer
ISO	Independent system operator
LADWP	Los Angeles Department of Water and Power
LMP	Locational marginal price
NERC	North American Electric Reliability Council
NTAC	Northwest Transmission Assessment Committee
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
OASIS	Open-Access Same-Time Information System
OR DOE	Oregon Department of Energy
PIER	Public Interest Energy Research
PG&E	Pacific Gas and Electric
PTO	Participating transmission owner
R&D	Research and development
RMATS	Rocky Mountain Area Transmission Study
RPS	Renewable Portfolio Standard
RTO	Regional transmission organization
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMUD	Sacramento Municipal Utility District
SSG-WI	Seams Steering Group, Western Interconnection
STEP	Southwest Transmission Expansion Plan
SWAT	Southwest Area Transmission Planning Group

SWRTA	Southwest Regional Transmission Association
TEAM	Transmission Economic Assessment Methodology
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WGA	Western Governor’s Association
WICTPP	Western Interconnection Coordinated Transmission Planning Process
WIEB	Western Interstate Electricity Board
WRTA	Western Regional Transmission Association
WSCC	Western Systems Coordinating Council

Executive Summary

The objective of this Public Interest Energy Research (PIER) scoping project is to identify options for public interest research and development (R&D) that will improve transmission-planning tools, techniques, and methods. The project is intended to help the PIER Transmission Program to identify and assess potential *transmission- planning R&D* activities. It does not address current transmission-planning activities or public interest R&D activities focused on other aspects of electricity transmission.

We gathered the information for this project through interviews with key stakeholders and review of transmission-planning documents relevant to California. The interviewees represent a wide range of engineering, regulatory, and policy expertise and responsibility. Most are directly involved in state and regional transmission-planning activities. The interviewees provided information on both technical and institutional challenges to current transmission planning.

Electricity transmission facilities are an enduring and highly visible part of society's infrastructure. It takes many years to plan and site transmission assets, which, once built, have lives of 30 years or longer. The interconnectedness of the transmission system means that the interests of many parties and institutions are affected both directly and indirectly by transmission-planning decisions. Yet there is no single forum or venue in which the concerns of all parties and stakeholders can be heard, much less addressed. Consequently, there are many transmission planning activities underway in the West, which present both common and unique challenges.

The institutional challenges to transmission planning far outweigh the technical challenges. R&D activities alone cannot resolve institutional challenges. For example, even with exact models, perfect forecasts, flawless power-flow tools, and ideal security criteria to address the many technical challenges, the planning process will remain subject to a host of non-technical stakeholder concerns and federal/state laws and policies. However, research could focus on information and tools that facilitate the public debate necessary to reach consensus on major transmission projects. Two important research topics in this area would be: methods for readily accessible presentation of information and reliance on mutually agreed upon tools (which may not be necessarily the most technically advanced) that can be easily used by all stakeholders. Improving the level of discourse through advances in these two areas can help clarify the underlying differences of opinion and values that drive current debates and identify options that might effectively address stakeholders' concerns.

The issue of uncertainty, in both assumptions and analysis methods, emerged as a persistent theme in discussions of virtually every aspect of the transmission planning, evaluation, and approval process. Traditional tools do not directly assess the many, inescapable uncertainties that are inherent in all planning processes. Responsible users of these tools should account explicitly for imperfect information and forecasts using techniques such as multiple-scenario analysis. The entire process of transmission planning and evaluation would benefit from tools that quantify the effects of uncertainty or that allow for consistent treatment of different perceptions by different stakeholders regarding the sources or magnitudes of uncertainty.

The project team distilled from interviews and literature review six topic areas for future transmission planning and 17 distinct R&D activities that fall under these headings, as follows:[1]

1. Support and extend the Transmission Economic Assessment Methodology (TEAM) under development by the California ISO
    - Market simulation and market-power analysis
    - Transport vs. direct current (DC) vs. alternating current (AC) power-flow analysis
    - Uncertainty analysis and techniques
    - Economic modeling and evaluation of seams
2. Harmonize transmission planning methods/approaches
    - Multi-scale models
    - Formal integration of bus-level load forecasting with system-level load forecasting
3. Expand the scope and focus of transmission planning
    - Longer-term scenario analysis
    - Generation technology choice and location
    - Demand-side alternatives to transmission
    - Integration of natural gas pipeline and electricity transmission planning
    - Macro-economic studies
4. Support regional transmission-planning activities
    - Common regional databases and information exchange
5. Enhance transmission-corridor assessment and planning
    - Transmission-corridor planning/assessment tools
6. Address leading technical issues in transmission planning
    - Probabilistic vs. deterministic reliability criteria
    - Voltage/reactive reserve modeling
    - Load modeling
    - Deliverability

The findings in this report do not necessarily reflect the views of the CEC and are intended for use, along with other materials, by PIER staff to facilitate discussions with stakeholders that will ultimately lead to development of a portfolio of transmission-planning R&D activities. The process, timing, and procedures needed for development and implementation of these activities are outside the scope of this report.

[1] No priority is implied by the ordering of these headings and research activities.

1. Introduction

Reliable and affordable electricity for California depends critically on a robust electricity transmission system. Currently, turmoil in electricity markets, uncertain opportunities for profitable transmission investments, and public concerns regarding the impacts of transmission on the environment and on public health have created a challenging environment in which to undertake transmission-system enhancements.

The objective of this California Energy Commission (CEC) Public Interest Energy Research (PIER) scoping project is to identify options for public interest R&D that will improve transmission-planning tools, techniques, and methods. The scope of this project is limited to identifying potential *transmission planning R&D* activities. It does not address actual, current transmission planning or public interest R&D activities for other aspects of transmission.

This report is intended to help PIER staff organize and assess transmission R&D needs consistent with the requirements and needs of the PIER program. The findings in this report are intended for use, along with other materials, by PIER staff to facilitate discussions with stakeholders that will ultimately lead to the development of a portfolio of transmission-planning R&D activities. The process, timing, and procedures needed for development and implementation of future public interest research on transmission planning are outside the scope of this report. Moreover, the findings in this report do not necessarily reflect the views of the CEC.

The project was undertaken in two phases:

1. Fact-finding on current transmission-planning activities and R&D needs, and
2. Development of potential transmission-planning R&D areas.

Both phases of the project relied on interviews with key stakeholders and review of transmission-planning documents. Interviews were conducted with a large number of stakeholders involved in or affected by transmission planning in California. The interviewees were experts in and responsible for a wide range of engineering, regulatory, and policy issues and activities. Most are directly involved in state and regional transmission-planning activities. The interviewees supplied information on both technical and institutional challenges to current transmission planning processes.

The interviews were conducted in person and discussed three topics: this study and its purpose, current transmission-planning practices and issues, and transmission-planning research needs. The interviews were not rigid and the discussion flowed freely among the topics of current practices, gaps, and research.

Seventeen interviews were conducted with staff from the CEC, the California Independent System Operator (CAISO), all three California Investor-Owned Utilities (IOUs), the California Public Utilities Commission Los Angeles Department of Water and Power (LADWP), both western power-marketing administrations, and others within the region. The interviews are listed in **Appendix A**. The project team, in consultation with CEC PIER staff and as a result of interviews with key stakeholders, also identified and reviewed a large number of documents related to transmission planning. The documents reviewed by the project team are listed in **Appendix B**.

This first outcome from the fact-finding process was an appreciation for the challenges faced by transmission planners and the multitude of transmission-planning activities currently under way in the West. **Section 2** summarizes these activities and the institutions involved in them. We describe both the organizations that plan transmission as well as how, in technical terms, they conduct their planning activities. In addition, we describe, when relevant, how the different organizations and their planning activities interact.

The second outcome from the fact-finding process was the wide variety of suggestions and perspectives offered by the interviewees regarding potential transmission-planning research topics. The project team organized this input into 17 potential research activities that fall under six topic areas. **Section 3** discusses each of the six topic areas:

1. Support and extend the Transmission Economic Assessment Methodology (TEAM) being developed by the California ISO
2. Harmonize transmission planning methods/approaches
3. Expand the scope and focus of transmission planning
4. Support regional transmission-planning activities
5. Enhance transmission-corridor assessment and planning
6. Address leading technical issues in transmission planning

The overviews presented in Section 3 of this report focus on the rationales for and key elements of R&D needed for each topic area.

Section 4 summarizes the 17 potential research activities that emerge from the six topic areas described in Section 3. The summary of the research activities addresses the following subjects for each: objectives, need, users, challenges and considerations, possible approaches, measures of success, and required effort.

2. Review of Transmission-Planning Activities in California and the West

This section summarizes current transmission-planning processes, primarily within California and introduces related processes that feed (and are fed by) these activities both from within and outside of the state. We begin with an overview of challenges currently facing transmission planners and the major stakeholders involved in transmission planning. We then describe individual transmission-planning processes and stakeholder involvement. The discussions also describe, when relevant, the interactions of different processes and participants.

2.1 Transmission-Planning Challenges

The challenges facing transmission planners reflect the historic development of California's transmission system, the dramatic changes introduced by the restructuring of California's electricity system (culminating with the crises of 2000-2001), and growing public concern regarding the impacts of transmission-line construction.

In the past, utilities planned transmission jointly with generation. The purpose of transmission was to bring power from distant generation sources to meet local demand. Because the planning was conducted by vertically integrated firms, it was straightforward to trade off generation and transmission costs, i.e., the added cost of building transmission to access cheaper sources of remote generation versus the higher cost of building and operating generation closer to load. California and the West pioneered the extension of these trade-off principles across both state and institutional lines by constructing multiple long-distance transmission lines to both the northwest and the southwest to facilitate the cost-effective import and export of power between large geographic regions. Reliable operation of these interconnections required new transmission technologies and unprecedented inter-regional cooperation. The Western Electricity Coordinating Council (WECC), which voluntarily oversees regional electricity reliability issues, has long served as the West's forum for discussions of inter-regional transmission planning.

When the Federal Energy Regulatory Commission (FERC), followed by California's AB 1890 legislation, directed utilities in the mid-1990s to functionally unbundle transmission from generation and provide non-discriminatory access to their transmission lines, the landscape for transmission and transmission planning changed dramatically. The California Independent System Operator (CAISO) was created to operate the transmission assets of the state's three investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), as well as those of other Participating Transmission Owners (PTOs).[2] The CAISO also had to accommodate the operation of a separately created wholesale spot market for bulk electricity, the California Power Exchange. IOUs divested themselves of their fossil-fueled generation assets, and independent power producers (IPPs) and power marketers (sometimes owning no generation assets) began actively participating in California's wholesale electricity markets. The transmission network is the

[2] The other major PTO in the state is Southern Cities, which comprises Anaheim, Azusa, Banning, Colton, and Riverside.

common carrier for this market and its physical attributes define the effective scope of this market.

For the first few years, the new markets appeared to work as designed. Wholesale prices were, for the most part, low, and utilities were able to recover their so-called stranded assets. However, starting in the summer of 2000, flaws in the design of California's wholesale markets resulted in unprecedented, sustained, high wholesale market prices. Before the crisis was over, PG&E and SCE were in severe financial distress, the California Power Exchange had collapsed, and Californians had endured repeated rolling blackouts.

Although many factors helped create the situation (e.g., absence of long-term supply contracts, high reliance by IOUs on the spot market), there is broad agreement that inadequate transmission capacity (e.g., Path 15) and the problems associated with planning and building new transmission facilities contributed to the crises. In this regard, it is notable that the last two major interregional transmission lines built in California -- the third Pacific AC Intertie and the Mead-Adelanto/Mead-Phoenix project – were both built in the early/mid-1990s by California's municipal, not investor-owned, utilities (and WAPA).

In the wake of the electricity crisis of 2000-2001, focus has shifted toward remedying the causes and addressing the elements of the electricity industry restructuring process that had remained incomplete. Transmission and transmission planning are of particular significance in this process.

Electricity transmission is an enduring and highly visible part of society's infrastructure. It takes many years to plan and site transmission, and, once built, transmission assets have physical lives of 30 or more years. The interconnectedness of the transmission system means that the interests of many parties and institutions are affected, directly or indirectly, by transmission planning decisions. Ensuring the reliability of the transmission network is a public good.[3] At the same time, there is no single forum or unifying venue for transmission policies and decisions. Instead, there are many transmission planning activities underway at any given time in California and the West with different scopes, geographic span, and time horizons. Among the many institutions where these policies and decisions are handled, the ability and influence of the affected stakeholders varies considerably. Transmission-planning processes in California and the West consists of many inter-related elements:

1. **Responsibility for transmission planning and construction** is divided between the PTOs and CAISO within the CAISO footprint. CAISO is responsible for planning transmission and can direct PTOs to build transmission. The PTOs must get approval for the construction of a specific line, build the line, and seek recovery for the investment through rates.[4]

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[3] EPG (Electric Power Group). 2003. *Review of Transmission System, Strategic Benefits, Planning Issues and Policy Recommendations.* Oct.

[4] The situation is different for California's municipal utilities; responsibility for transmission planning and construction of municipal utilities remains un-divided and resides within each company and their respective oversight jurisdictions.

In order to justify new investment, PTOs must demonstrate to their regulator or governing board that their ratepayers will benefit from a proposed new line even though the interconnected transmission system provides benefits to many parties, not just local ratepayers. These larger benefits are difficult to address in a venue that focuses primarily on the benefits that will accrue to the party that will pay the cost of a new line (i.e., the local ratepayers). Regulatory rules require that benefits considered in a transmission construction proceeding must be assignable directly to those paying for the investment.

2. **Responsibility for transmission oversight** is divided between federal and state regulatory authorities (and local governing boards in the case of municipal utilities). FERC authorizes tariffs for transmission services and rules that govern CAISO operations. FERC also establishes policies for generation interconnection. These policies directly influence generators' decisions about where to site their facilities, which in turn creates the demands for transmission service that must be accommodated or at least taken into account by transmission planners. FERC mandated interconnection policies have led independent power producers to site new generation in locations with ready access to fuel or water but these policies do not encourage consideration of the transmission facilities that will be needed to ensure delivery of the power to customers. Pricing policies have also not clearly signaled the value of siting generation in locations that would ease rather than exacerbate transmission congestion (or the costs of not doing so). A *de facto* policy has resulted in which transmission is said to be "chasing" generation, which is at odds with the long lead times associated with building transmission facilities compared to the much shorter lead times associated with building generation facilities.[5]

The California Public Utilities Commission (CPUC) authorizes the retail rates charged by the IOUs for electricity service (which includes recovery of transmission expenses approved by FERC). CPUC also issues the Certificate of Public Need and Convenience (CPNC) that authorizes an IOU to begin construction of a transmission line. Currently, the CPUC is seeking ways to harmonize and streamline its approval process by linking it explicitly to CAISO's planning processes.[6]

3. **Responsibility for some aspects of transmission planning within the state** is shared among different state agencies. Although the CPUC has siting authority for IOU transmission projects, the CEC has siting authority for generation projects greater than 50MW in size. The CEC is also responsible for preparing a biennial Integrated Energy Policy Report. This report includes "assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand and prices," as well as, "an assessment of system reliability and the need for resource additions."[7]

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[5] K. Hattevik. 2003. *Report on the Current Transmission Planning Process for Investor Owned Utilities*. California Public Utilities Commission. Dec.

[6] CPUC. 2004. *Order Instituting Rulemaking on Policies and Practices for the Commission's Transmission Assessment Process.* Jan. 2004.

[7] CEC. 2003. *Integrated Energy Policy Report*. Dec. 2003.

4. **Ownership of transmission assets** is divided among private (IOUs) and public utilities. See Figure 1.[8] CAISO and its PTOs are responsible for delivering approximately 80 percent of California's electricity, and public utilities deliver the remaining 20 percent. IOU transmission projects must be approved by CPUC; municipal utility transmission projects are approved by the utility's local governing boards. As noted above, the last major interregional transmission line to California was built by a consortium of municipal utilities. The Los Angeles Department of Water and Power (LADWP), the largest municipal utility in the country, is a significant transmission owner. It has built transmission lines across California to Utah, Arizona, Nevada, and the Pacific Northwest to secure a diversified portfolio of low-cost generation for its customers.

5. **Transmission is regional** in nature, crossing state boundaries and falling under the purview of federal and state agencies and administrations. California imports a significant percentage of its electricity from the Pacific Northwest and desert southwest, and new generation to serve California electricity loads is increasingly being built out of state. Regional institutions, first the Committee on Regional Electric Power Cooperation (CREPC) and then the Seams Steering Group, Western Interconnection (SSG-WI), have arisen to begin facilitating information sharing on new generation projects and to initiate coordinated, long-range transmission-planning studies. None of these regional institutions has authority for transmission planning or siting, however.

6. **State policies** introduce new directions for transmission planning priorities. For example, California adopted targets for renewable-energy generation to meet 20 percent of the state's electricity needs by 2017. Most of those involved agree that a significant portion of the target will be met through a combination of in-state and out-of-state wind generation. New transmission lines will be required to ensure delivery of this increased supply of wind generation to California electricity users.

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[8] CEC Website: http://www.energy.ca.gov/maps/utility_service.html

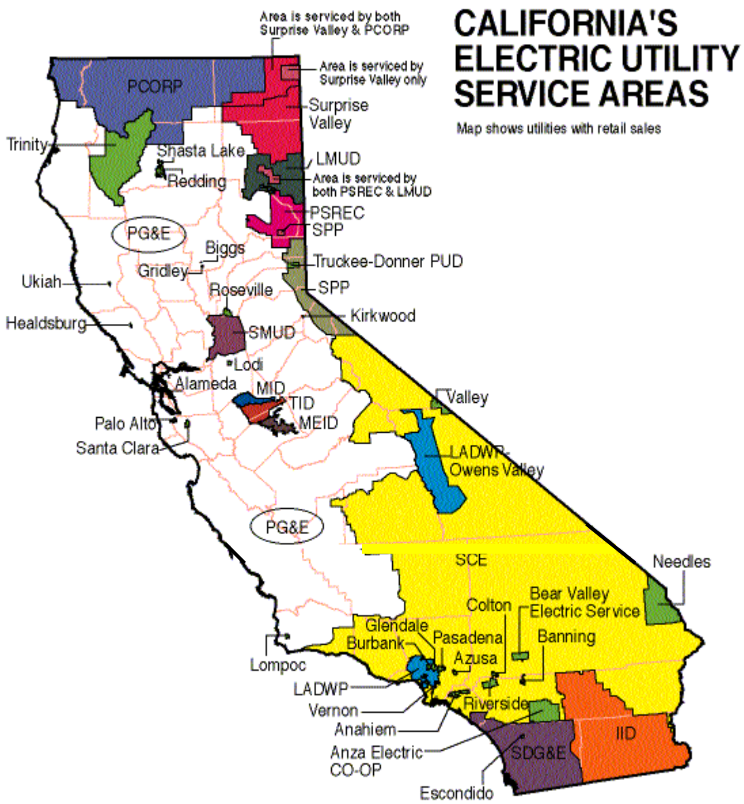

Figure 1. California's Electric Utility Service Areas

Finally, overlaying the six elements of the transmission planning process described above, public concerns are now significantly represented in the transmission-siting process. Conflict resulting from public involvement in the process highlights vividly mismatches in the interests of the beneficiaries of transmission lines and of those who bear the costs of the lines. During the early 1990s, public awareness of the potential linkages between health and the electromagnetic fields created by transmission lines surfaced as a major public policy issue. More recently, long delays in construction of transmission lines planned many years before, coupled with population growth along the rights-of-way secured when the lines were first planned, has led to conflicts between local communities opposing and utilities seeking to build transmission lines.

Public participation in decision making for major infrastructure investments is a hallmark of state policy, but there are significant technical and resource barriers to the public's involvement in major decision processes. Moreover, public participation is typically invited during final reviews of specific proposed lines when it is difficult or too late to consider a broad range of alternatives rather than when the public's input could be most helpful, i.e., early in the process when a broader range of alternatives (including non-transmission) can more readily be considered.

2.2 California's Transmission Planning Processes

As noted above, transmission planning and decision making take place in many venues. Currently, the most significant of these venues in the state is led by CAISO. Following a description of CAISO's current transmission planning process and efforts to address new issues raised by industry restructuring, we discuss supporting planning activities conducted by the state's utilities and the CPUC's efforts to streamline and to harmonize with CAISO their review of projects proposed by IOUs.

2.2.1 CAISO Transmission Planning Process

CAISO is the lead transmission-planning institution for the state of California for three reasons: its control over a vast transmission infrastructure, its role as the initial evaluator of IOU transmission plans, and its role in coordinating transmission planning with other entities in the West.

2.2.1.1 CAISO's Current Transmission-Planning Process

CAISO's current transmission-planning process focuses exclusively on assessing the impacts of transmission projects on system reliability. The process requires bus-level load and generation forecasts and uses power system models that include detailed representations of transmission to review static and dynamic system responses to contingency outages both with and without the transmission options under consideration. The system is studied under expected peak load conditions to simulate stressed operation situations. Generation is expected to be operated in an economic fashion based on engineering measures of plant efficiency and forecasted fuel costs. Detailed transmission modeling allows power-flow and voltage solutions to be compared to CAISO's Grid Planning Criteria. These criteria embody planning criteria promulgated by the North American Electric Reliability Council (NERC) and WECC, as well as specialized CAISO reliability criteria for California. Transmission plans are generally regarded as adequate if they meet the reliability criteria for the contingency scenarios. Currently, little or no acknowledgment is given to enhancements of the grid's strength or flexibility beyond what the reliability criteria specify.

Projects enter the CAISO's transmission-planning process through many avenues. Figure 2 outlines the various paths by which projects may enter CAISO's processes and the steps involved in CAISO's evaluation, culminating with the decision to recommend construction (the triangular conclusion of the process). For the purposes of this discussion, "planning" refers to review of proposals to build specific transmission facilities. Alternatives to specific proposed projects are not entertained at this stage; other processes described below in this section consider alternatives.[9]

A majority of new transmission projects involve requests for interconnection into the grid. The applicants may be IPPs, IOUs, or municipal power authorities. Interconnection requests are first

[9] This information is based primarily on the "ISO Grid Coordinated Planning Process," documented at http://www2.caiso.com/docs/2001/06/11/2001061116583410598.pdf.

submitted to the appropriate PTO to review the local impact of the proposed interconnection. If the interconnection is deemed to have system impact, an impact study is performed by the PTO and reviewed by CAISO to verify that the interconnection meets CAISO's Grid Planning Criteria. The system impact study notes whether additions to the grid are needed to reasonably accommodate the new interconnection. If grid upgrades appear necessary, a facilities study is done to specify the necessary reinforcement to the grid and the alternative approaches that may be taken. The facilities study is reviewed by CAISO, and the WECC review process (described below in Section 2.3) may be undertaken at this point or even earlier for projects that are expected to have significant system impacts.

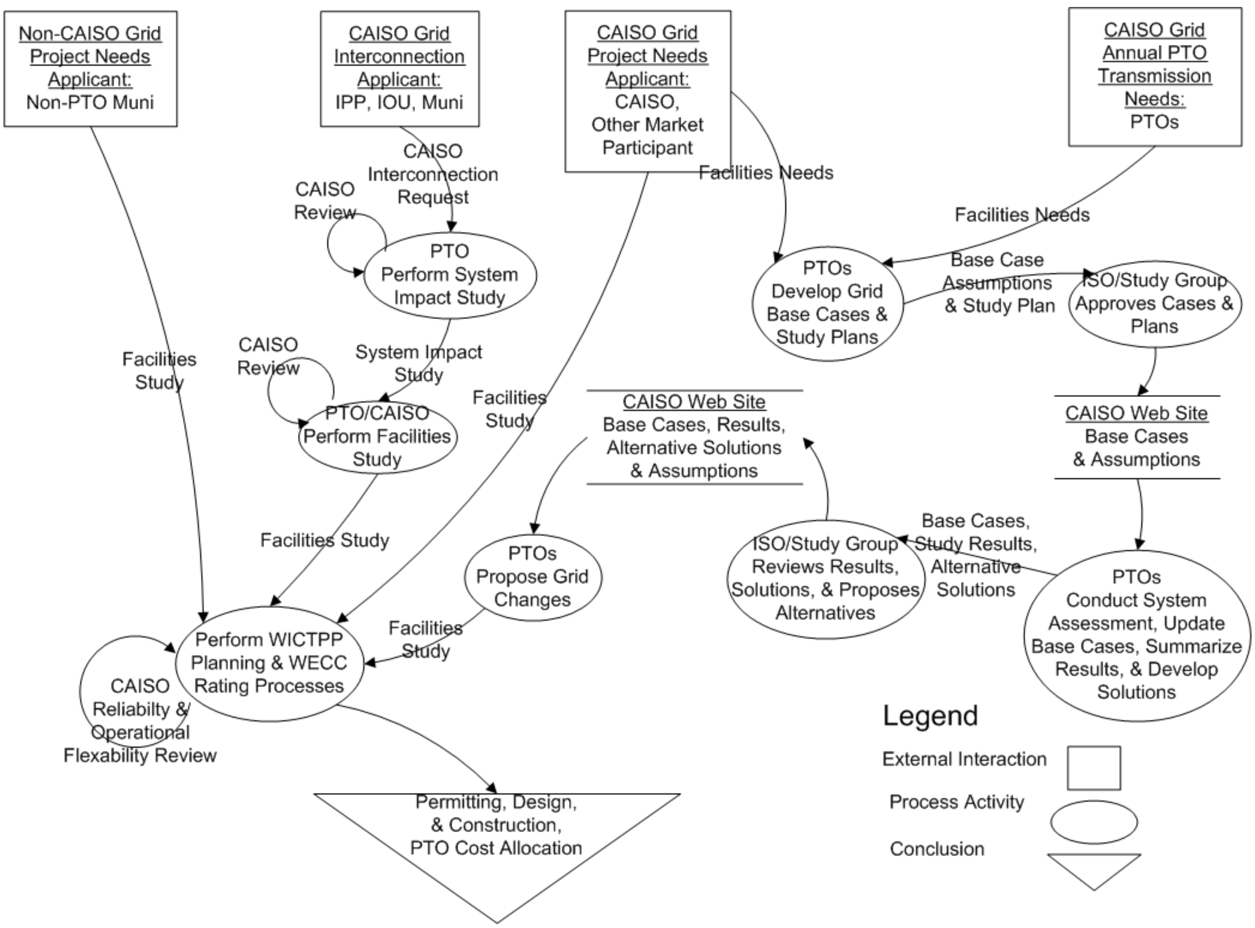

Figure 2. CAISO Transmission Planning Process

A second major source of transmission projects is the annual transmission assessment prepared by each PTO (see Section 2.2.2). These plans describe proposed grid additions envisioned by PTO planning staff for the upcoming a five-year (at a minimum) or often 10-year planning horizon. The PTO's annual plans take into account facility needs submitted by CAISO or other market participants. A plan for studying the proposed additions is developed by the PTOs in open public meetings involving market participants. A set of corresponding base-case models, which represent the system prior to the inclusion of a proposed addition, is constructed to support the anticipated studies.

CAISO and market participants review and approve the PTOs study plans and base-case materials, which are ultimately posted on a CAISO website where all stakeholders can access them. All parties use the base cases to conduct independent assessments and review each other's conclusions concerning system impacts and possible alternative approaches. The CAISO Grid Planning Criteria are applied to a five-year planning horizon in the assessment. As a result of these studies, the base-case information is updated and refined, the study results are summarized, and alternative solutions are developed. The resulting base-case data, assessment conclusions, and potential alternatives are posted on the CAISO website for all participants to review. The PTO also submits the facility studies to the WECC review process. The overall process is to be completed within one year.

Transmission projects are also proposed directly by market participants and CAISO. These plans are coordinated with the appropriate PTO annual planning process (see below) and, when built, would be "owned" by the PTO, not CAISO. CAISO may shepherd specific projects directly to the WECC review process for expediency.

2.2.1.2 CAISO's Proposed New Economic Assessment Process

The CAISO transmission-planning process has been in place for several years. Recently, CAISO staff has enlarged their basic evaluation method to account for a number of issues that were not previously considered, including the economic impacts of transmission, other issues raised by the restructuring of the electricity industry, and concerns such as uncertainty.[10] [11]

CAISO's Transmission Enhancement Assessment Methodology (TEAM) (Figure 3) brings several new elements – some of which are akin to those that are considered in integrated resource planning - into the transmission planning process; TEAM:

- Considers generation and demand-side alternatives for transmission expansion,
- Evaluates benefits of transmission expansion for market competitiveness,
- Includes interdependency of generation and transmission investments,
- Assesses benefits under a wider range of potential system conditions than was previously considered,
- Includes a detailed regional network representation appropriate for assessing large expansion projects, and
- Measures benefits regionally and separately for consumers, producers, and transmission owners.

[10] A. Sheffrin. 2004. *Transmission Economic Assessment Methodology (TEAM) Introduction, Background, and Schedule*. CAISO Stakeholder Meeting Presentation, February.
[11] CAISO, *Transmission Economic Assessment Methodology*, June 2004, http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

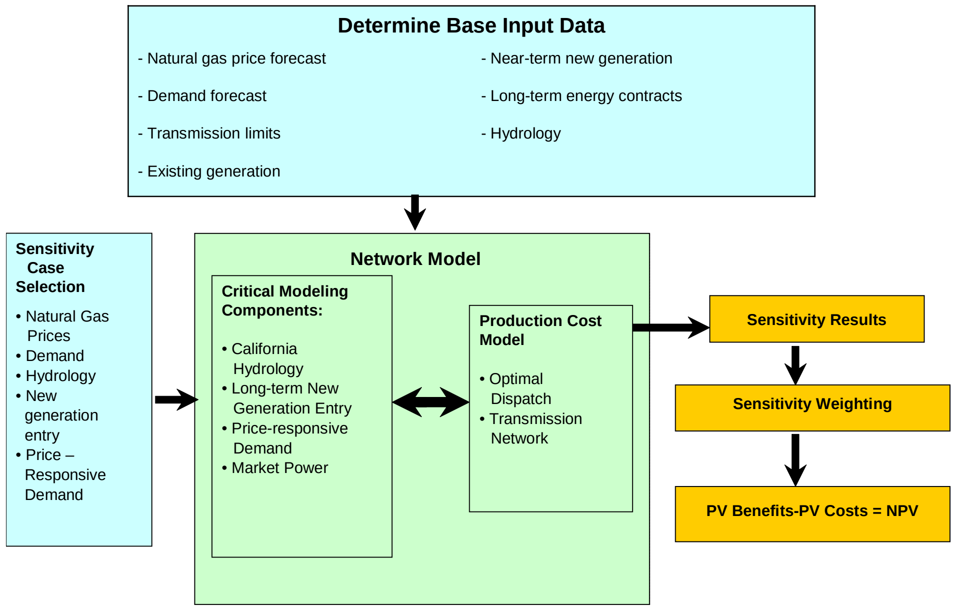

Figure 3. CAISO's Proposed Transmission Economic Assessment Methodology (TEAM)

TEAM evaluates the economic costs and benefits of proposed transmission projects, adding a more detailed economic dimension to transmission planning than was previously included.[12] It simulates the operation of a competitive wholesale electricity market to forecast market prices and considers the ability and effect of market participants to exert market power to raise market prices. It can measure the value of transmission expansion for enhancing inter-zonal/regional electricity trade (and also for reducing the market power of participants). And it explicitly treats uncertainty in fuel-price forecasts and generation investments explicitly.

TEAM is sensitive to the fact that transmission plans' costs and benefits are location dependent, allowing calculation of costs and benefits from a variety of perspectives, including society at large (with explicit treatment of consumer and producer surplus) and the ratepayers of the PTO who would pay for the project.

The simulation software that integrates these economic issues with a DC, linearized transmission model was developed by Drayton Analytics in their PLEXOS Electricity Market Simulation tool.[13] CAISO's expectation is that market participants will acquire the tool and supporting data

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[12] CAISO and London Economics International. 2003. *A Proposed Methodology for Evaluating the Economic Benefits of Transmission Expansions in a Restructured Wholesale Electricity Market*, Feb 28.

[13] G. Drayton, M. McCoy, M. Pereira, E. Cazalet, M. Johannis, D. Phillips. 2004. "Transmission Expansion Planning in the Western Interconnection – The Planning Process and the Analytical Tools that Will Be Needed to Do the Job," to be presented at the IEEE 2004 Power System Conference and Exhibition, Oct 2004, NY, NY.

sets developed by CAISO and conduct transmission planning on their own or in conjunction with CAISO-led processes using the new CAISO methodology.

2.2.2 Utility-led Transmission Planning

California's three IOUs (PG&E, SCE, and SDG&E) own, as PTOs, approximately 80 percent of the state's transmission infrastructure. Public power authorities and municipal utilities own the remaining 20 percent. The IOUs are major stakeholders in CAISO's transmission planning and their annual transmission-planning assessments feed directly into CAISO's process. Non-PTO municipal utilities participate in the CAISO's transmission-planning processes at their option. Currently, Riverside, Azusa, Banning, Colton, and Anaheim, known collectively as the Southern Cities, are the only PTO in the state that is not an IOU.

The majority of transmission projects planned by the utilities are small in size with impacts limited to the service territory boundaries of a single firm. These projects are incorporated into the PTOs' annual plans but are not studied by CAISO for system impacts.

The main focus of utility transmission planning is to accommodate load growth and meet the reliability criteria promulgated by NERC, WECC, and CAISO. The process involves forecasting bus-level generation profiles and load growth (explained below), estimating winter and summer peak demand conditions and other conditions that will stress the system in the future, defining single and multiple contingency scenarios for addressing the reliability criteria, and describing any specific characteristics of the utility system that contribute to reliable operation.

Because utility distribution and transmission remain vertically integrated, distribution feeder history provides good bottom-up information on trends in load growth. From this base of information, utilities construct transmission-level bus-load forecasts for the various planning time horizons (generally one to five years). CEC supply and demand forecasts provide longer-term, aggregated targets that, in principle, must be reconciled with the utilities' shorter-term, and more geographically disaggregated models and data. For example, utility transmission planners may apportion the aggregated load to the bus-level based on feeder-level information. The result is a bus-level demand forecast that is used to predict peak load in the near term and supports studies of at least five years into the future.

Forecasting generation on a bus-level basis has been challenging. In our interviews, an IOU and a large municipal utility both reported difficulty in predicting where and what amount of new generation would interconnect to their systems and when existing units retire. Recent experience indicates that congestion may also appear unexpectedly at off-peak time periods because of long-term generation contracts. These contracts can lead to power-delivery patterns that heavily load lines in unexpected (non-production-cost-efficient, at least when considered from standpoint of historic patterns of dispatch) ways. A utility may study these and other special situations in addition to providing the on-peak base case information required by the CAISO and WECC transmission-planning processes. Today, utilities plan to the specified deterministic standards but also may use some relatively crude tools (e.g., spreadsheets) to consider the probabilistic impacts of various outage scenarios and the relative costs and benefits for a transmission project.

Based on the results of their internal studies, utilities also review - to varying degrees - deliverability and reliability issues as well as transmission-expansion alternatives. For these studies, they use a bevy of tools including full AC power flows, transient and dynamic stability simulations, voltage stability studies, and short-circuit analysis. The PTOs' best expansion alternatives are brought forward as part of their annual planning process along with the base-case information required for CAISO transmission-planning models and the WECC review. Utility dispatched load interruption is addressed in PTOs' transmission plans; however, other alternatives, such as demand response or locational incentives for generation siting are generally not considered.

2.2.3 CPUC's Role in Transmission Planning

CPUC plays an important role in transmission planning through its oversight of the state's three large IOUs. IOUs must obtain a CPNC from the CPUC before building new or expanding existing transmission lines. As Figure 2 shows, CPUC currently becomes involved for this purpose during the final stage of planning for a transmission project. In the past, an additional round of evaluation was required for a CPNC.

The Energy Action Plan directed CPUC, CEC, and CAISO to improve coordination of their transmission-planning activities (CEC/CPA/CPUC 2003). A subsequent January 2004 ruling by the CPUC directed CAISO to file its new evaluation method (i.e., TEAM) with the CPUC in June 2004. It is expected that, CPUC will, if it approves the new method, adopt the method as the primary basis for evaluating IOU applications for CPNCs for new transmission projects. If CPUC adopts CAISO's evaluation method, the review processes of the two bodies will be streamlined and harmonized. CPUC also plans to take an active role earlier in the CAISO transmission-planning process than has been the case in the past, so that decision-making will flow more smoothly. Figure 4 shows the enhanced transmission planning process envisioned by CPUC.

In a separate ruling, CPUC has indicated that it will review and approve IOUs' resource portfolio plans, among other things, to ensure appropriate balance between supply and demand-side options as well as examine transmission-planning implications of IOU resource choices. This review is an effort to address resource adequacy issues to support the "front end" of the CAISO transmission-planning process.

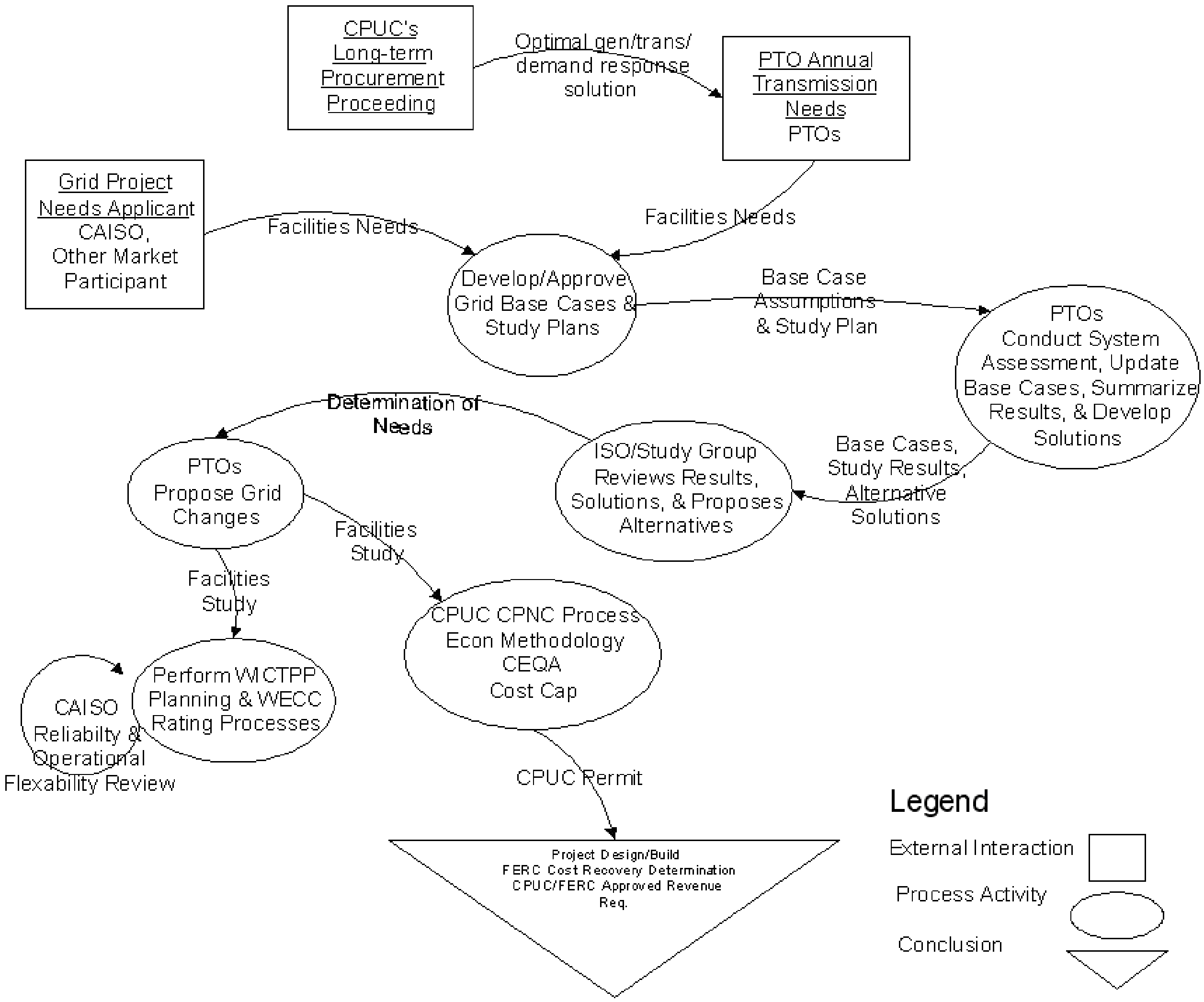

Figure 4. CPUC Proposed Changes to the Annual PTO/CAISO Transmission-Planning Process

2.3 Related Regional Transmission Planning Activities in the West

By design, California imports significant amounts of power from both the Pacific Northwest and the desert southwest. In addition to the economic benefits of exchange with these regions, the interconnections have contributed to the overall reliability of the western grid. As a result of these interconnections, California transmission-planning activities have important connections with regional transmission-planning activities. The most significant of these has been joint reliability reviews through WECC. Recently, a number of voluntary regional transmission-planning efforts have arisen to address regional economic and resource development issues as well.[14] Coordination among these activities is facilitated by members' active formal and informal participation in each other's meetings and planning activities.

[14] B. Anderson. 2004. *Transmission Planning: Institutional Issues in the West*. CREPC report, 15 Jan.

2.3.1 Western Electricity Coordinating Council

WECC is a voluntary, cooperative organization composed of electric utility interests in the western interconnected region of North America. The western interconnected grid includes the 10 western U.S. states, as well as western Canada and a small portion of Mexico.[15] WECC has its roots in the Western Systems Coordinating Council (WSCC) which was formed in 1967 by 40 electric power organizations with bulk generation and/or transmission interests. In 2002, WECC was created through the merger of the WSCC, the Southwest Regional Transmission Association (SWRTA), and the Western Regional Transmission Association (WRTA). WECC is one of the 10 regional councils that make up NERC.

All of California's electric power entities (CAISO, IOUs, municipal utilities, etc.) participate in the WECC to coordinate transmission planning for reliable operation of the grid. WECC's Planning Coordination Committee, subcommittees, and work groups allow participating organizations to share information and coordinate transmission planning. For example, referring back to Figures 2 and 4, we can see that CAISO, through its participation in WECC, is informed of all projects submitted to the Western Interconnection Coordinated Transmission Planning Process (WICTTP), including those not submitted by PTOs. Collectively, from a transmission planning standpoint,[16] WECC's committees:

- Review and recommend system planning criteria,
- Compile and disseminate information pertaining to planned generation and transmission facilities, and
- Perform studies to assess the reliability of the WECC interconnected system.

All transmission owners in California submit qualifying proposed transmission projects for review through WECC's WICTTP prior to seeking permits for construction of facilities. Qualifying facilities are generally those that operate at 100kV or above, but the defining criterion is whether operation of a proposed facility will affect the reliability of the western interconnection.

The reviews that take place through the WICTTP are triggered by transmission plans submitted by its membership. WECC cannot direct the construction of transmission, but it can discourage projects or recommend changes to plans because of reliability concerns that emerge in its review of plans.

[15] www.wecc.biz

[16] WECC committees also address issues related to reliable operation of the western interconnection. For example, these committees provide the forum for establishing the operational line ratings for transmission in the west. These ratings set the reliable carrying capacity of each transmission component, incorporating the thermal constraints, contingency constraints (ability of the system to withstand loss of equipment), and stability constraints (limits on capacity due to transient, dynamic, or voltage stability issues).

WECC member organizations primarily use the Shaw PTI PSS/E and GE PSLF tools to coordinate the creation and maintenance of system-wide transmission planning models and data used in their analyses. Both tools rely on standardized formats that allow members to exchange data, which facilitates review and verification of findings. Both static-security (power-flow) and transient-stability tools are used in analyzing the western system. Individual organizations also use internally developed analysis tools or tools from other vendors; however, they all convert data to the PTI or GE formats for data exchange.

2.3.2 Committee on Regional Electric Power Cooperation

The Committee on Regional Electric Power Cooperation (CREPC) is the main body of Western Interstate Energy Board (WIEB) for addressing regional transmission-planning issues. WIEB represents 12 western states and the three bordering western Canadian provinces. It also serves as the energy arm of the Western Governors Association (WGA), which "...addresses important policy and governance issues in the West, advances the role of the Western states in the federal system, and strengthens the social and economic fabric of the region." It also, "…acts as a center of innovation and promotes shared development of solutions to regional problems."[17]

WGA has been active in addressing transmission planning in the West. In 2000, WGA, through CREPC, published the first-ever, integrated, region-wide assessment of western transmission planning needs and issues.[18]

CREPC membership consists of staff from the western state electricity agencies. CREPC provides a forum for its members to study and make recommendations on a host of issues including market seams, wind power interconnection, demand response, and resource assessment in the West.

2.3.3 Seams Steering Group – Western Interconnection (SSG-WI)

SSG-WI comprises representatives from each of the three bodies that are expected to be granted Regional Transmission Organizations (RTO) status in the West: CAISO, RTO West (otherwise known as Gridwest), and WestConnect. These three bodies are seeking to coordinate their activities through SSG-WI in anticipation of eventual recognition as RTOs by FERC.

SSG-WI "…serves as the discussion forum for facilitating the creation of a Seamless Western Market and for proposing resolutions for issues associated with differences in RTO practices and procedures."[19] SSG-WI has a Planning Work Group that supports transmission planning for "a competitive and seamless west-wide wholesale electricity market." Recently, the Planning Work

[17] http://www.westgov.org

[18] Western Governors' Association. 2001. *Conceptual Plans for Electricity Transmission in the West.*

[19] http://www.ssg-wi.com/

Group released a major long-range look at western resource development and potential transmission needs.[20]

Figure 5 shows the proposed SSG-WI planning function in relation to other western regional groups involved in planning. Establishment of this process, with its cross-organizational interactions, is a work in progress.

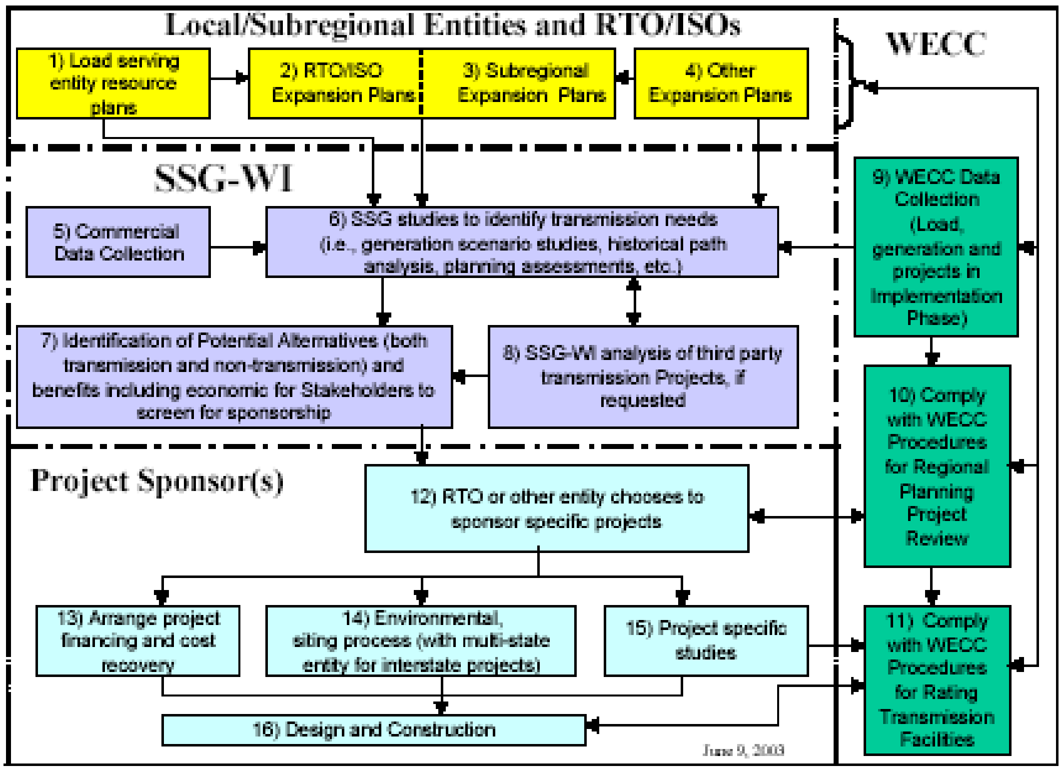

Figure 5. SSG-WI Transmission Planning Interactions within the Western Interconnection

The SSG-WI Planning Working Group is actively looking into the system-modeling and software tools needed to address transmission planning issues for the whole western region. (PacifiCorp has, in particular, been instrumental role in creating a comprehensive system-wide model that can be used to support regional transmission-planning studies). The Planning Working Group sees a significant role for optimization tools in simulating least-cost system dispatch over a defined time horizon; they are reviewing the state of the art available in these tools and what improvements will allow these tools to effectively address transmission-planning questions. The group wishes to be able to review non-transmission alternatives, including favorable generation siting and demand-side contributions.

[20] SSG-WI. 2003. "Framework for Expansion of the Western Interconnection Transmission System," Oct.

It is worth noting that there is a question about the sustainability of SSG-WI, if FERC does not grant RTO status to the participants. Currently, CAISO is the only one of the three participants that is responsible for control area and transmission operations.[21]

2.3.4 Related Regional Transmission Planning Activities

In addition to WECC, CREPC, and SSG-WI, a number of subregional initiatives address transmission infrastructure issues. Most of these subregional initiatives are information-sharing forums to identify and develop consensus for needed new transmission projects, including coordination of technical and financial resources to move projects from ideas to formal proposals. In addition, the West's two large federal power-marketing administrations, Bonneville and Western, each own significant transmission assets and consequently engage in transmission planning that affects California. We briefly describe the subregional and power-marketing administration activities below.

The Southwest Transmission Expansion Plan (STEP) was created to address transmission capacity in Arizona, Southern Nevada, Southern California, and Northern Mexico that is insufficient to support the generation expansion plans for this subregion.[22] STEP has already studied specific transmission-expansion projects, including a new line between Arizona and California and a new transmission line to San Diego. CAISO is actively involved in STEP. Results of STEP studies are inputs to the CAISO transmission-planning process.

The Northwest Power Pool (NWPP) is a voluntary organization of electricity generating companies in the Pacific Northwest, and British Columbia and Alberta Canada. The Rocky Mountain Area Transmission Study group (RMATS) is an open forum to study transmission needs in Colorado, Idaho, Montana, Utah, and Wyoming. The Southwest Area Transmission Planning group (SWAT), formerly known as the Central Arizona Transmission Study group (CATS), includes Arizona and New Mexico and parts of southern California, west Texas, southern Nevada, and southern Colorado.

The Western Area Power Administration (WAPA) was created to market and transmit electric power from all multi-use hydro projects in the western U.S. except those overseen by the Bonneville Power Administration (BPA).[23] WAPA owns transmission facilities throughout the

[21] RTO West includes British Columbia, Idaho, Nevada, Oregon, Utah, Washington, and portions of Montana and Wyoming. The group has filed plans with FERC for creating an RTO but appears to be several years away from becoming a viable independent transmission operator and participating in regional transmission planning.

WestConnect includes Arizona, New Mexico, and West Texas. Transmission reservations will be handled by a common open-access, same-time information system (OASIS); however, like RTO West, this group appears to be several years away from becoming an independent transmission operator and establishing transmission-planning processes.

[22] http://www1.caiso.com/docs/2002/11/04/2002110417450022131.html

[23] http://www.wapa.gov/

West, including California (through its Sierra Nevada Regional Office in Folsom CA). PG&E has held the contract to operate WAPA's northern California transmission lines, which are, in turn, operated by CAISO. WAPA has sponsored the initiative to upgrade California's Path 15. WAPA conducts transmission planning primarily through its regional offices.

BPA owns and operates most of the transmission network in the Pacific Northwest, interconnecting Washington, Oregon, Idaho, Montana, California, and British Columbia. BPA supports significant transmission planning and participates in many regional and subregional transmission-planning efforts. BPA's markets the vast Columbia and Snake River hydropower resources, which makes it a significant regional player, and has a long history of coordinated transmission planning with California to provide access to these resources, particularly during peak summer conditions. BPA has invested significant effort in refining its ability to model the unique hydrological resources in its portfolio.

BPA is sensitive to the regional impacts of generation and transmission within its footprint and recently reviewed its transmission planning process to incorporate analysis of non-wires alternatives to transmission expansion.[24] This process engages a broad group of stakeholders early in the proposal process so that participants can understand the difficult economic and environmental tradeoffs and help shape solutions. BPA's consideration of alternatives to transmission may be helpful in guiding future changes in the transmission planning processes of California and the western region in general.

The Northwest Power and Conservation Council (NWPCC) was created by the U.S. Congress and is funded by BPA revenues "to give the citizens of Idaho, Montana, Oregon and Washington a stronger voice in determining the future of key resources common to all four states — namely, the electricity generated at and fish and wildlife affected by the Columbia River Basin hydropower dams."[25] NWPCC is mandated to develop and maintain a 20-year electric power plan that guarantees adequate and reliable energy at the lowest economic and environmental cost to the northwest. NWPPC's plans and policies are implemented by numerous agencies including BPA, U.S. Army Corps of Engineers, U.S. Bureau of Reclamation, and FERC.

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[24] Foley, T. and E. Hirst. 2001. *Expansion of BPA Transmission Planning Capabilities*. Energy and Environmental Economics, Inc. November. also see: BPA Non-Wires Solutions Update, http://www.transmission.bpa.gov/PlanProj/Non-Construction_Round_Table/

[25] http://www.nwcouncil.org/about

3. Transmission Planning R&D Needs and Opportunities

Our project team interviewed a large number of stakeholders directly involved in or directly affected by transmission planning in California. These stakeholders provided a wealth of information on technical and institutional challenges to current transmission planning processes. This section synthesizes the information we gathered into an integrated discussion of transmission planning R&D needs and opportunities.

Six major topic areas emerged from our interviews:

1. Support and extend the economic assessment methodology (TEAM) being developed by California ISO
2. Harmonize transmission-planning methods/approaches
3. Expand the scope and focus of transmission planning
4. Support regional transmission-planning activities
5. Enhance transmission-corridor assessment and planning
6. Address leading technical issues in transmission planning

This section discusses these six topic areas. The next section of the report describes 17 individual transmission planning R&D activities that emerge from these topic areas. The references are included in portions of the discussions below are not a comprehensive list for any particular topic area; a complete literature review was beyond the scope of this report.

Before discussing the six topic areas, we offer two overall perspectives on the discussions that follow. These perspectives form an important context for understanding and ultimately implementing the R&D activities we have identified.

First, the most consistent and important observation that emerges from our interviews is that the institutional challenges facing transmission planners far outweigh the technical challenges. R&D can help address both challenges, but it is not realistic to expect R&D by itself to resolve the institutional challenges. For example, even with dramatic technical advances – exact models, perfect forecasts, flawless power-flow tools, and ideal security criteria – the planning process will remain subject to a host of non-technical stakeholder concerns and federal/state laws and policies. However, to address these institutional challenges, research into tools that facilitate the public debate necessary to reach consensus on major transmission projects would be of great value. Research goals should include easy and readily accessible presentation of information and reliance on mutually agreed upon tools (which may not be necessarily the most technically advanced) that can be readily used by all stakeholders. Even R&D advances such as these could not, by themselves, resolve the underlying differences of opinion and values that drive current debates; they would, however, help to clarify these differences and facilitate identification of options that might better address stakeholders' concerns.

Second, uncertainty is a persistent theme underlying virtually every aspect of the transmission planning, evaluation, and approval process. Traditional tools do not directly assess the many, inescapable uncertainties that are inherent in all models and in all data they on which they rely. Responsible users of these tools cannot ignore these uncertainties which, in transmission planning, routinely have a major influence on the results of analyses. Users should account explicitly for imperfect information and forecasts, using techniques such as multiple scenario analysis. As noted above, transmission planning is subject to many stakeholder concerns that involve fundamental differences of opinion regarding the future. These differences are inevitable given the inherent uncertainty in assumptions regarding future needs and resource developments. Transmission planning and evaluation would benefit from tools that quantify the effects of uncertainty in ways that will better inform decision making or allow for more consistent treatment of different stakeholder perceptions of the sources or magnitudes of uncertainty.

We ask our readers to keep these two overall observations in mind while reviewing in the following subsections the six topic areas that emerged from our interviews.

3.1 Support and Extend Transmission Economic Assessment Methodology (TEAM) Developed by California ISO

CAISO is in the process of developing an enhanced method that accounts for both economic and reliability considerations in assessments of proposed transmission projects. It is expected that TEAM analysis will soon be accepted as the primary basis upon which the CPUC will determine the need for any proposed transmission project. In view of the importance of CAISO's method, it is imperative that it be as sound as possible and updated regularly, as our understanding advances.

How to comprehensively analyze the economics of electric power markets remains a research issue. Straightforward analysis of a market occurs when it is assumed to be competitive, accurate system-wide cost data and perfect demand forecasts are available, and models of sufficient complexity can be used to predict market outcomes. One of the greatest concerns is that electric power markets may not be competitive and that analysis that relies on cost data will miss market power problems. Problems of market "seams" also complicate economic analysis because assumptions need to be made for trade and markups for bilateral transactions between, inside, and outside the market. There is always the issue of identifying the most practical, accurate tool for a task; for example, there is a largely unstudied issue about whether the so-called "DC power flow" model provides a sufficient approximation to the "AC power flow" model for market model/transmission planning purposes. The DC power flow model is practical but has not been proved (or disproved) to be adequate for this purpose. CAISO is taking steps to explicitly address uncertainty through the use of scenarios. Other, more technical methods for addressing uncertainty have also been suggested.

How to assess the potential for participants to exercise un-due market power or otherwise un-fairly exploit the market has received considerable attention. Aggregate measures, such as concentration metrics, can identify instances in which a small number of participants may have the ability to exercise some control over the market.[26] A common metric, the Herfindahl-Hirschman Index (HHI), is used by the Department of Justice and has been adopted by FERC and the ISOs as one measure of market competitiveness. These types of metrics are often difficult to apply to electric power markets because network limitations may allow local exercise

[26] A highly concentrated market has a few dominant participants and is not considered competitive. A lightly concentrated or unconcentrated market has many equal participants and is considered competitive.

of market power that may not be apparent if the market analyzed without explicit consideration of these limitations (which are time-varying and depend on the actions of all other market participants taken together). Overall, there may be many participants, but system constraints can create conditions in which a "load pocket" can only be served by a small number of concentrated resources. Simulation techniques may identify instances of market power by repeated study of a particular operating condition with varying offer profiles to see if any profiles enable a significant increase in prices over what would be considered competitive.[27] These simulation methods require prohibitively large computational resources. Another technique that combines power-flow equations with a sensitivity analysis may identify small groups that have the simultaneous ability to increase offers and revenues; this approach has not been tested on a large ISO-scale system, however.[28]

Currently, TEAM estimates markups by increasing offers disproportionately, assigning the largest increases to participants that have the greatest market share. This approach is intuitive and may identify certain market-power opportunities. It has the advantage of being straightforward and easily applied. It also has the drawbacks of being somewhat ad hoc, and it may miss instances of local market power that cannot be identified by concentration measures. More research is needed to develop a computationally efficient way to determine when a market may not be competitive and to estimate the resulting markup.

A number of questions arise regarding whether models and tools are adequate or appropriate to the task in transmission planning: When are models lacking critical information? Can models be too detailed? What is the trade-off between tool complexity and accuracy? In our research for this report, we found that the tools and their levels of detail were often chosen because they were convenient, not necessarily because they were the best for the job. As an example, we discuss the DC power-flow approximation below (we also revisit this topic when we discuss reliability under the topic of N-1 and voltage stability criteria and in the area of modeling uncertainty).

Current computational tools rely on a simplified representation of the actual, physical electricity grid. In the CAISO evaluation method, the DC power-flow model is used rather than a simpler transport model or a more complex AC power-flow model. In a recent TEAM stakeholder meeting the CAISO explained that the computational time required for repeated AC power flow analyses made it impractical. The issues and tradeoffs involved in this decision are discussed in some detail in the CAISO's Market Surveillance Committee opinion on the TEAM method.[29] A summary of the reasons is that transport models fail to capture important loop flows and overestimate transmission capabilities, and the AC power-flow model is time consuming. Although the DC power-flow model appears to be the only practical option it has drawbacks: it

[27]Borenstein, S., J.B. Bushnell, and F. Wolak. 2002. "Measuring Market Inefficiencies in California's Deregulated Electricity Industry." *American Economic Review*, Vol 92, No. 5, Dec.
[28] Lesieutre, B.C., R.J. Thomas, and T.D. Mount. 2003. *A Revenue Sensitivity Approach for the Identification and Quantification of Market Power in Electric Energy Markets*. presented at the IEEE Power Engineering Society General Meeting, Toronto, Canada, July.
[29] CAISO MSC. 2004. *Comments on the California ISO's Transmission Expansion Assessment Methodology (TEAM)*, June 1.
http://www.caiso.com/docs/2004/06/01/200406011457422435.pdf

neglects voltages and reactive power limits, and it does not fully account for transmission line losses. It may identify different binding constraints than the AC power-flow model, and it also results in different locational marginal prices. A comparison of DC and AC power-flow solutions for a model of the Midwest system shows a "small" average difference of slightly more than $2/MWh,[30] which, when calculated for the entire loading in a system of that size, represents a significant amount of money. The AC and DC power-flow models also identify different binding constraints in the same example. This example is a limited study of a single system condition. A comprehensive comparison of transport vs. AC vs. DC power flow models has not been performed for energy markets. A study should determine whether the difference is simply a constant bias that is unimportant for transmission planning, or whether the difference may be pronounced and unevenly distributed because of misidentified binding constraints or some other unknown flaw. Understanding this issue is especially important for studies that quantify economic benefits of alternatives, which is necessary for transmission planning. The uncertainty introduced by using a DC power flow instead of an AC power flow in a benefits study could overwhelm the values compared.

Uncertainty is pervasive in studies of transmission enhancements, most prominently in projections of future conditions. In practice, scenario analysis is used to anticipate possible futures of interest, such as the most likely case, the best case, the worst case, and a variety of permutations in between. Additional sensitivity studies may be preformed to clarify the results. The results of scenarios are examined as a basis for decisions. A thorough description of the possible outcomes that quantified the degree of uncertainty would aid in analysis and decision making. Once quantified, approaches are needed to account for the strategic value of transmission, as an "insurance policy" against the contingencies postulated in scenario analyses.

The exhaustive analysis of uncertainty for decision making is complicated. Consideration of uncertainty affects early decisions, which in turn affect later uncertainty and, consequently, later decisions. Optimal resource investment involves a probabilistic dynamic program for which sophisticated algorithms need to be developed to address the model complexity and uncertainty.

The most common approach to uncertainty analysis in modeling is the Monte Carlo approach, which characterizes the uncertain parameters and inputs using a joint probability distribution. Combinations of parameters or inputs are randomly selected, and the evaluation of a large number of combinations yields a distribution of outcomes. Direct treatment of uncertainty is limited by computational power: A Monte Carlo simulation that takes into account all of the important dimensions of uncertain information in the models in question is not feasible. A whole field of inquiry is dedicated to addressing this computational burden by using advanced algorithms and models. The most common techniques attempt to approximate the result of the Monte Carlo simulation using a small number of judiciously chosen selections. An interesting alternative approach is to develop a very simple approximate model that accommodates both the uncertainty representation and the traditional Monte Carlo simulation. (Such an approach has

[30] Overbye, T.J, Xu Chen, and Yan Sun. 2004. *A Comparison of the AC and DC Power Flow Models for LMP Calculations*. presented at the 37th Hawaii International Conference on System Sciences, January.

been applied to models of global climate change and power system dynamics[31 32].) Specific uncertainty techniques and models should be developed for transmission planning. Data to support the models will need to be gathered and analyzed, taking into account their interdependencies in a logically consistent manner. The structure of the models themselves must also treat uncertainty in an integrated and consistent manner that recognizes that some uncertainties are not independent of one another.

Seams between markets affect the manner in which trade is conducted inside, outside, and between markets. It is difficult to model the effect of this trade on the market, but this information may be critical for long-term economic analysis. Many studies apply a "hurdle rate" to represent various transaction costs associated with trade between markets.[33] These studies use a wide range of applied hurdle rates: between $3/MWh and $15/MWh. These rates are justified intuitively, but no detailed empirical study is available to support or evaluate the values used. Part of the problem with modeling the effect of seams is the lack of publicly available information. Electricity markets are relatively new, and attention is not typically focused on bilateral contracts across market seams. It is conceivable that an empirical study could be accomplished using data contained in the FERC quarterly reports of electricity sales.[34] The data in those reports may be rich enough to use in assessing on the hurdle rate representation and determining appropriate rates for trade across seams.

Because California is moving to a wholesale market based on locational marginal prices (LMPs), LMP forecasting tools would help assess the incentives for new transmission and generation investment. One of the properties of LMPs is the explicit description of incentives to site new resources where needed. Accurate LMP forecasts would allow investors to anticipate opportunities. Lead time for making resource investments would benefit everyone. Such a tool has to meet a number of challenges: it should be computationally efficient; it should avoid repeated, detailed simulation; and it should accurately estimate both expected LMPs and volatility. Volatility from model-based estimators is often underestimated,[35] yet there is a need

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[31] Webster, M., M.A. Tatang, and G.J. McCrae. 1996. *Application of the probabilistic collocation method for an uncertainty analysis of a simple ocean model*. Joint Program on the Science and Policy of Global Change, Cambridge MA: Massachusetts Institute of Technology Technical Report 4, January.

[32] Hockenberry, J.R. and B.C. Lesieutre. forthcoming. "Evaluation of Uncertainty in Dynamic Simulations of Power System Models: The Probabilistic Collocation Method," to appear in *IEEE Transactions on Power Systems*.

[33] MISO. 2004. *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*. http://www.midwestiso.org/news/2004/Initial_%20Report_Wis_Benefits-Costs_032604.pdf

[34] http://www.ferc.gov/docs-filing/eqr.asp This a link to the main page for electric quarterly reports on the FERC website.

[35] There is a theoretical reason for this underestimation. Estimators optimized to minimize the difference between the actual value and the estimated value of a quantity, in a mean-squared-error sense, will understate the volatility of that quantity. Mathematically, the variance of the estimate will be less than the variance of the original quantity.

for accurate volatility estimates because investment strategies consider both price and price volatility.

3.2 Harmonize Transmission Planning Methods/Approaches

On the general theme of choosing the right models and tools to address a given problem, discussed earlier, we consider whether the available data can support the models and tools for longer-term transmission planning. There is a gap between detailed engineering models for transmission planning and the uncertainty inherent in forecasted information. This gap can be bridged either by enhancing forecasting tools to provide bus-level supply and demand information used in engineering tools, or by developing appropriate approximate network models that effectively incorporate the necessarily uncertain forecasted aggregate supply and demand.

To properly value new transmission, its benefits must be calculated over some future time horizon. Assumptions about supply availability and demand needs are incorporated into models to quantify the benefits of new transmission. In the short term, best-guess updates to existing conditions provide adequate information for detailed engineering power-flow analysis. This type of analysis uses a fine-scale representation of the system and is considered most accurate. Over the long term, forecasts for supply and demand are not currently available on a finer scale but are calculated at a coarse-scale, regional level. This information does not fit directly into traditional engineering models.

There appear to be two possible routes for reconciling forecasts and engineering tools: increase the granularity of the forecasts to provide bus-level information or to develop multi-scale planning tools that directly incorporate regional forecasts. The benefit of the former is that existing, trusted engineering tools may be employed, but the drawback is that the already uncertain regional forecasts will become even more uncertain as a result of the spatial disaggregation, possibly to the point where the results cannot be trusted. The second approach requires basic research to develop such models and make sure that they will support engineering needs. The uncertainty in any long-term analysis means that it is highly likely that all future needs will not be perfectly met by decisions made today. It would be ideal to have assurances that only small system adjustments will be required for decisions based on the approximate models and uncertain information.

Some prior bus-level forecasting and subsequent power-flow analyses have been performed, and tools for load projections are quite advanced (less advanced for supply). One of the utilities that we interviewed reports that it has been able to closely reconcile its distribution level projections with CEC's aggregate system-level load projections. Supply forecasts are more challenging, and at least in one SSG-WI study of the Pacific Northwest, different scenarios were developed to account for uncertainty in the detailed distribution of supply forecasts. That is, uncertainty was handled by evaluation of different possible cases. It is argued that any transmission need identified for a majority of scenarios is an excellent candidate for consideration.

Tools may be developed to disaggregate regional supply and demand forecasts. This disaggregation may include a description of the uncertainty in the forecasts. A refined stochastic power-flow tool can be developed to evaluate the uncertainty to help prioritize transmission needs. This stochastic tool should be more sophisticated than scenario analysis and should approach the accuracy of Monte Carlo simulation. Additionally, research could support the development of new, multi-scale models to directly incorporate regional demand and supply forecasts. Although these would be approximate in engineering terms, their results may be more accurate than those obtained from detailed engineering models because they avoid the potential large uncertainty introduced in disaggregating forecasts.

In addition to the rough scale of regional forecasts, there are other reasons that data may be better handled in an aggregate form instead of in detail. Privacy and national security concerns are often raised with regard to the details about the power-system network, including ownership, physical location, and equipment operational efficiency. In many regional studies, these sorts of details may not be necessary or ranges of values may be adequate for a planning analysis and the precise nature of sensitive information can be omitted. Similarly, data can be aggregated into coarse-grained constructs that may be more appropriate for regional studies than the details used for local planning analysis. Today's regional power system information modeling solution is generally brute force: Detailed network and economic models from different organizations are merged together to form a much bigger model of the same sort of data. Power-systems information technology research can be used to suggest regional models and tools that emphasize the issues of importance for regional planning while removing or hiding sensitive details.

3.3 Expand the Scope and Focus of Transmission Planning

Transmission planning involves more than evaluating engineering information supplied by detailed power-flow analyses. A broad range of resources, in addition to generation, must be considered to compare transmission enhancement options to non-transmission alternatives. These alternatives include demand-side resources and energy-transport options such as natural gas pipelines and, in the future, possibly hydrogen pipelines. Evaluation of transmission corridors must also take societal concerns (e.g., impacts on sensitive habitats) into account.

Long-term studies require estimates of both load needs and generation resources. Currently, generation forecasts are based on filed requests for plant permits, forecasts of future load, and assumptions regarding the transmission system. Future transmission needs are based on load forecasts and assumed generation resources. Generation and transmission are not usually assessed simultaneously so the assessments are not consistent with one another. This problem is compounded in regional planning activities which require that data on generation (and loads) from different jurisdictions or planning entities must be harmonized and combined for studies to be internally consistent. Checking for consistency requires a small effort, but reconciling differences may require a moderate effort. There are both technical and institutional issues to address in these efforts as market simulation tools cannot yet model entry and exit of generators to and from the market, much less location and siting.

Transmission-planning activities are sometimes challenged by stakeholders who believe that inadequate consideration has been given to demand-side alternatives (including distributed generation, energy efficiency, and demand response) that could supplant or delay the need for new transmission facilities. A fixed-load forecast is traditionally used as the basis for consideration of generation and transmission planning alternatives. Consideration of demand-side options would require that the load forecast become a variable that could be affected by the final plan. Research in this area would focus on addressing the question of how to include consideration of demand-side options in the planning process.

Consideration of demand-side options is difficult because data on the nature and extent of the demand-side resource are not well defined and subject to uncertainty. For example, comprehensive data are not available on market adoption of demand-side options, and, in particular, on the effects of explicit strategies to accelerate market adoption. This information should be available by geographic region. Although California utilities have evaluated their demand-side management (DSM) programs, these evaluations have not focused extensively on market adoption and locational issues.[36] In addition, there is significant mistrust (based on lack of experience) about the "hardness" of (i.e., the ability to count on load reductions expected from) demand-side options. Similarly, electricity tariff design policies and practices (e.g., stand-by charges), which are key market drivers for distributed generation are in flux at CPUC.

In addition to the question of how demand-side options can be incorporated in the transmission-planning process, there is the question of when these options would be addressed. Procedurally, transmission planning tends to follow a linear process in making resource-acquisition decisions. But if transmission and generation are to be traded off against demand-side resources, the linear process must become iterative. BPA has begun to explore some of these issues.[37]

With regard to natural gas and other future transportable energy sources, the issue is clear: energy transferred over transmission lines as electricity is substitutable with energy transferred through pipelines. Economics and engineering may favor one option over another, but the final decision may involve other stakeholder concerns. If a pipeline already exists and local beneficiaries oppose a transmission line, a new, small generator may be the best alternative to transmission. There are many paths to the best solution; comparisons among transmission and pipeline options will help stakeholders evaluate alternatives.

Many of the concerns and consequences of transmission enhancement cannot be anticipated by engineering analysis. Macroeconomic studies can address concerns such as property values and economic growth to quantify the impact of different transmission options. Proximity to transmission lines may affect property values, and it is widely believed that the access to energy supply (through new transmission facilities) can spur economic growth; a transmission project designed to connect distant supply to existing demand may promote economic growth at the anticipated load center as well as at new locations along the way. Both of these effects should be quantifiable through data analysis.

Macroeconomic studies have been conducted in the past by utilities and others in the electricity industry. During our interviews we heard a desire to update these studies and ensure that their findings are defensible. While interviewees believe that past studies were accurate and unbiased, other stakeholders have perceived a conflict of interest in the studies being conducted by the utilities that might stand to profit from the new transmission capacity. The CEC is well

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[36] http://www.calmac.org/

[37] Foley, T. and E. Hirst. 2001. *Expansion of BPA Transmission Planning Capabilities*. Energy and Environmental Economics, Inc., Nov.

positioned to perform these studies in place of utilities because of its ability to obtain and analyze historical data and its role in addressing the state's energy needs.

Another type of study that could be incorporated in the transmission-planning process would focus on the value of electricity-system reliability in making decisions about transmission investments. Typically this value is binary: it is either extremely high if the system fails reliability standards without the transmission upgrade or zero if reliability standards are satisfied without the upgrade. However, this binary point of view may be changing. CAISO reports that during testimony for the upgrade to Path 15, specific questions were asked regarding the value of reliability, separate from questions about economic value. Transmission projects can be based solely on the need to ensure reliability; however, economically driven enhancement projects will also have an impact on reliability. Knowing whether a certain line will increase or decrease reliability and placing an economic value on this change will aid in the evaluation of a proposed plan. Little has been published on this topic. One possible approach would value the relation between a project and the change in expected loss of load over some length of time. Taking this a step further, a method to quantify an economic value of reliability could be used in every evaluation of the need for new transmission, eliminating the binary approach used now for reliability. This would require a shift to assessing reliability using a probabilistic approach, a topic we address below. Regardless of how the value of reliability is taken into account, there is a need to update studies of the value of reliability, which assess how much reliability is worth to different customers as a function of different level of electric service reliability (e.g., as a function of the frequency and duration of outages, as well as impacts of power quality).

3.4 Support Regional Transmission-Planning Activities

Transmission planning in the West involves many organizations that focus on local, subregional, and regional activities. The creation of various subregional and regional groups makes sense in view of the complexities of the considerations at each level, the different stakeholders, and the different time horizons of different interests. Still, many of these groups' concerns overlap: service areas of interest, electricity network models, generation and demand forecasts, and time frames (one to three years, one to five years, three to 10 years, etc.).

Participants in these groups would like their efforts to be better coordinated. Two technical advances would support this coordination: 1) establishment, maintenance, and exchange of regional data models appropriate for planning activities, and 2) development of tools that can reasonably handle these large models and/or recast detailed equipment and forecast models into forms that lend themselves to addressing regional questions about system reliability, stability, and configuration (to facilitate responsiveness to regional macro-economic change). Although these improvements would not address the socio-political challenges to consistent, coordinated leadership, they would ensure that well-intentioned initiatives do not wither away for lack of technical information.

Today's regional efforts, such as SSG-WI's Planning Work Group, require volunteer organizations to champion the creation of data models for the cases and time horizons of interest. These models originate from local planning models or from existing regional data models that need to be tailored to reflect the conditions being addressed. The format of these data is based on the forms used by proprietary software such as Shaw-PTI's PSS/E or GE's PSLF. The tools to export portions of a local or regional model can be crude, and the tools used to create large, regional models by stitching together overlapping pieces of smaller models are ad hoc and unique. The latest in information science needs to be brought to bear on these problems, but knowledge of power systems also needs to be emphasized if progress is to be made. Research efforts can look to data exchange breakthroughs being made in the operations modeling area with IEC 61970[38]. Model management and exchange forums, with representation from the major western transmission planning organizations together with power analysis tool vendors and information integration specialists, can discuss model exchange and assembly approaches and debate their appropriateness. CEC research initiatives would be appropriate in this area because most regional planning groups involve California organizations and/or concerns. Because the information involved in this research area is sensitive, approaches that respect business privacy and national security are required.

3.5 Enhance Transmission Corridor Assessment and Planning

Assessing transmission corridors is a complicated process. The transmission owner has to consider engineering requirements and costs, as well as the non-technical concerns of many stakeholders interested in land usage, the environment, health, equity of benefits, and more. The siting process can be impeded by sometimes lengthy review processes and contentious objections from local communities. The current process is not ideal for achieving consensus. Very specific projects with complete engineering and financial analyses are often submitted for approval before interested stakeholders can voice their concerns. Actions to address stakeholder objections then take the form of incremental changes to the plans. The process could become less adversarial and more conducive to consensus if stakeholders were invited to participate early. Developing an advanced corridor-assessment process with these features could foster public buy-in and enable early (and less costly) acquisition of land.

As part of the 2004 IEPR Update process, CEC has heard public comment on the value and need for site-banking. CEC could take a proactive role in this area by supporting development of advanced corridor assessment tools that can form a common, agreed-upon base of information for comparing, contrasting, and discussing different transmission-siting options. Ideally, given agreement on the need to provide energy to a specific location or reach an attractive energy source, these tools would allow stakeholders to quickly assess, in terms of costs and interests, the tradeoffs among siting options.

Some interviewees recommended that such tools employ a geographic information system (GIS)-based visualization interface that allows users to overlay and display geographically that information of interest to different stakeholders. This would include topological information for line-of-sight considerations and engineering issues, environmental information (e.g., flora, endangered species habitat), land ownership and location of sacrosanct landmarks, and population. For many concerns, the CEC could also develop a database of geographic information that can be generally available as needed.

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[38] A. deVos, S.E. Widergren, J. Zhu. 2000. *XML for CIM Model Exchange*, Proceedings, IEEE PICA 2000.

Some basic tools for this purpose exist. SCE has worked with a software vendor, FACET, to develop an interface of this type.[39] SCE also reports that there is a need for research and development to improve the tool and supporting database so that they can be used effectively in public discussion. EPRI has demonstrated use of a similar tool to support future corridor assessments in Georgia.[40]

California's Renewable Portfolio Standard (RPS) may provide an impetus for developing and using such a tool, which could be used by CEC to compare corridor options for reaching certain valuable renewable resources. The tool could allow CEC to identify some preferred routes from topological and environmental concerns and also identify routes with "fatal flaws" that would render them unavailable. Although this assessment would not take the place of a detailed engineering or economic study, it would facilitate focused detailed studies by transmission investors without pre-approving projects.

3.6 Address Leading Technical Issues in Transmission Planning

Research is required to expand the currently limited capability of engineering models, tools, and methods for determining reliability and secure system operation. The traditional deterministic approach to reliability assessment does not account for the likelihood or impact of events that could disrupt system operation. Voltage stability is inadequately addressed by existing approaches, and detailed models for loads are uncertain at best.

The basis for secure operation and planning is the "N-1" ("N" minus one) reliability criterion. If the electricity grid, comprising "N" number of components, can operate within safe thermal, voltage, and stability limits despite the loss of any single element, (i.e., with N-1 components), the system is said to be secure. In practice, the N-1 criterion addresses multiple simultaneous outages that are considered sufficiently probable. (One interviewee specifically stated that these probable outages are events that have occurred three times in 10 years.) Engineering power-flow tools are used to determine whether post-contingency operating conditions violate safe limits. Both the N-1 criterion and power-flow tools need to be reconsidered and improved.

The N-1 reliability criterion is conceptually simple but there is concern that it is inadequate. Some multiple contingencies are more probable than other single contingencies, and some events have such a significant impact that they warrant attention even though they do not fall into the N-1 category. (The August 14, 2003 blackout was essentially an N-3 event.) It would be ideal to prioritize the contingency evaluation for reliability by considering both the probability and impact of an event. However, currently available information and tools limits the possibility for using this ideal approach. Research is needed to estimate the probability of events that would disrupt transmission and to develop tools that can efficiently find the events that would have significant impact. The success of these probabilistic estimations depends on consistent, credible data, taking into account that the data depend on operating conditions. An enumeration of all multiple simultaneous events is combinatorial in nature and is not feasible with existing

[39] http://www.facet.com/projects/SCE_Siting.html This is a link to a page on the FACET website that mentions the SCE corridor-siting project.
[40] Mahoney. J . 2004. *Electric Transmission Siting Methodology Project*. EPRI. Presentation to California Energy Commission. April 20.

computers. (A complete analysis of 10,000 component failures would require approximately 10,000 power flows for N-1 analysis, 50,000,000 for N-2 analysis, and 167,000,000,000 for N-3 analysis, etc.) Planners and operators who know and work with their systems have an excellent idea of which component failures are most important in terms of likelihood and impact and the sizes of grid events that require consideration. Nevertheless, a tool that can automatically screen for important events, combining probability and impact, would be valuable for system planning and secure operation. No such tool currently exists.

There is also concern that existing power-flow and stability tools are inadequate for assessing voltage stability for a given grid event. The power-flow tool allows users to find a feasible steady-state operating condition for the network before and after a contingency. Traditional generator dynamic stability evaluation is valid for a few seconds after an event. There is a gap in the analysis between a few seconds (traditional stability) and a few minutes (steady-state power flow) that is not considered. In this gap, there is little verification to ensure that the system will move to the operating condition predicted by the power-flow tool. Voltage stability is a particular concern because many voltage controls operate during this period. The system dynamic response needs to be considered when establishing security criteria, but the existing tools and models do not make this evaluation. A number of known techniques could be applied to this problem, including use of algorithms to speed up traditional models and development of multi-timescale models that separate dynamic phenomena. A research investigation could determine the most appropriate method and lead to the development of a tool to that would assess voltage stability more effectively than is possible currently.

In developing a tool to analyze voltage stability, limitations in current models need to be addressed. The interaction between demand and voltage is critical during the time frame in question, yet this relation between load and demand is one of the greatest uncertainties in power-system evaluation. Load modeling is discussed prominently in the power-engineering literature, usually in response to reports that post-mortem dynamic analyses of blackouts do not match the actual recorded dynamics until load-model parameters are adjusted.[41] In other words, appropriate mathematical representations for load models exist, but their parameters are not known with certainty. Research is needed to either improve models' characterization of load properties or to enhance tools that relate the uncertainty in load models to system performance. The former would be difficult because it is impossible to conduct controlled studies on loads; the only data available are those collected during severe grid disruptions when they occur. The latter approach could be undertaken using Monte Carlo techniques and the variants we discussed earlier (in subsection 3.1). As a result of the move to competitive electricity markets, emergency demand-response programs, if present, will need also to be considered. Transmission planning requires projections of future conditions, but acceptance and usage of emergency demand-response programs is uncertain.

An emerging transmission-planning issue related to markets is deliverability. In some electricity markets, sufficient energy and reserves must be procured to meet load, and the resources must be

[41] Kosterev, D.N., C.W. Taylor., and W.A. Mittelstadt. 1999. "Model Validation for the August 10, 1996 WSCC System Outage." *IEEE Transactions on Power Systems*, Vol. 14, No. 3, August, pp. 967-979.

deliverable to the load. Likewise, new generation facilities need to provide upgrades to the transmission system as well as the interconnection, to ensure that their power is deliverable. These issues have not yet been addressed in California but will need to be. It would be beneficial for this purpose to develop tools that can quickly determine deliverability capabilities in relation with plant siting and determine necessary transmission upgrades that will ensure deliverability. Traditional tools are not designed for this task. They either compute pair-wise source/sink capability or global incremental supply capability, neither of which directly addresses deliverability.

4. Description of Potential Transmission-Planning R&D Activities

This section describes 17 potential transmission planning R&D activities that emerged from the six topic areas described in Section 3. Each of the 17 activities is discussed using a common format to simplify comparisons. The format is to discuss the following issues related to each potential activity in the following order: objective, need, user, challenges, possible approaches, and required effort. The 17 activities are offered as examples rather than an exhaustive list of all possible research activities. They are based on suggestions from the interviewees and input from the project team. The estimate of effort is rough and intended only to give an idea of the order of magnitude differences in effort among the topics. In several instances we note linkages between or among research activities, especially in the areas of uncertainty and appropriate model choices.

The 17 potential research activities are presented, following the order of their categorization under the six topic areas from the previous section:

Support and extend CAISO's TEAM

1. Market simulation and market power analysis
2. Transport vs. DC vs. AC power-flow analysis
3. Uncertainty analysis and techniques
4. Economic modeling and evaluation of seams

Harmonize transmission planning methods/approaches

5. Multi-scale models
6. Formal integration of bus-level load forecasting with system-level load forecasting

Expand the scope and focus of transmission planning

7. Longer-term scenario analysis
8. Generation technology choice and location
9. Demand-side alternatives to transmission
10. Integration of natural gas pipeline and electricity transmission planning
11. Macro-economic studies

Support regional transmission-planning activities

12. Common regional databases and information exchange

Enhance transmission-corridor assessment and planning

13. Transmission-corridor planning/assessment tools

Address leading technical issues in transmission planning

14. Probabilistic vs. deterministic reliability criteria
15. Voltage/reactive reserve modeling
16. Load modeling
17. Deliverability

Title	**4.1 Market Simulation and Market-Power Analysis**
Objective	To determine the effect of market power in the CAISO electricity market for the purpose of evaluating the economic impact of transmission expansion
Need	One of the arguments for the economic benefit of transmission expansion is that it may reduce the potential for exercise of market power. To quantify this effect, it is necessary to detect and assess market-power opportunities in scenarios with and without the proposed transmission enhancement. Simple, straightforward approaches such as concentration measures will not capture local market-power opportunities gained through positions within an electrical network that offer locational advantage. Detailed simulations in which offers are varied in some manner (random or through learning) may expose instances where market power could be exercised. These types of simulations are prohibitive because of the numbers of scenarios and time periods that need to be considered. A sensitivity approach has been suggested in the literature, but it has not been tested on a large-ISO-scale system. A computationally efficient way is needed to identify instances of market power potential and estimate their economic effects.
“Users”	The users of a technique to identify and quantify market power will include CAISO in its assessment methodology and PTO and regional transmission planners who will share a common database will calculate market power in their own analyses.
Challenges and Considerations	CAISO’s new transmission expansion assessment evaluates the effect of a transmission enhancement over many time periods (every hour per target year) under different scenarios. It is impractical to consider some computationally intense market simulations to assess market power for every scenario/hour of interest. Simple approaches inspired by concentration measures are likely to capture only the most obvious instances of market power. Detection of subtle, local instances created by the topology of the electrical network is needed. Concentration measures could be applied locally if it were possible to automatically determine appropriate local areas. Tools for doing so are underdeveloped.
Possible Approaches	There are at least three possible approaches: 1. Identify market-power opportunities by examining revenue or profit sensitivities based on explicitly

	accounting for characteristics of the electrical network. Specifically target participants who can better their positions through their market bids. 2. Develop a technique to accelerate market simulations to identify and quantify market power markup. Acceleration could entail making the simulation faster, achieving the same results with fewer repeated simulations, or studying results to develop a simple metric that obviates the need for simulation. 3. Determine how to automatically apply market-concentration measures to local market-power problems. For example, identify load pockets and other network-constrained areas that may offer locational advantage.
Measures of Success	The research will be successful when its ideas or algorithms are incorporated in the CAISO methodology.
Required Effort	A significant effort will be required to both develop and prove a technique.

Title	**4.2 Transport vs. DC vs. AC Power-Flow Analysis**
Objective	To study the consequences of using planning models with different levels of technical detail in transmission-planning studies
Need	Transport, DC power-flow, and AC power-flow models represent the range from simplest and least accurate to complex and most accurate electricity grid models. Past studies often used production-cost models with an underlying transport model. These typically include detailed models of sources and costs of electricity but very simple models for transport from generation to loads, in which the network is modeled by links with capacity limits. It is implicitly assumed that the capacity of all lines is available for use, which allows well-developed algorithms to quickly analyze production-cost issues. In the actual network, however, congestion on any path will effectively limit the available capacity on the other paths. Not all capacity is available for use. Recognizing this limitation, detailed DC and even AC power-flow models are now being coupled with production-cost models to perform economic analysis. Ideally, the AC power flow is the most accurate model, but it is complex, requires significant computational resources, and sometimes exhibits computational problems that cause it to fail to converge. Presently CAISO's evaluations use an approximation, the DC power-flow model. This model captures the flow-based effects on limiting capacity in the network, and it can be used to calculate LMPs and evaluate congestion. Its limitation is that it is unable to directly enforce voltage and reactive power constraints and thus cannot determine the effect of voltage and reactive power on energy prices and congestion. Research is needed to determine appropriate models and tools for transmission planning, taking into account the level of modeling detail required and the level of detail of available data. Detailed models may be preferred when the error introduced by an approximate model exceeds the calculated values of interest. For example, the difference in LMP values between and the AC and DC models may have a larger impact than the differences calculated among different transmission scenarios. In contrast, use of the most detailed models is questionable when input data are not available to support these

	models. Future projections may be the limiting uncertainty, diminishing the need for exact grid models.
"Users"	Transmission planners and CAISO
Challenges and Considerations	A challenge may arise in obtaining the data required to run a detailed AC power-flow model, and it is possible that computational problems may arise when the power flows are run. This research is not likely to result in a simple yes/no result. It is expected to provide guidance regarding which models should be used for what purpose. Additional work may be required to develop multi-scale models that reflect uncertain inputs in an appropriate manner.
Possible Approaches	Design a benchmark system and analyze it using models with differing levels of detail. The benchmark should include hourly data for a designated test year. A full AC power-flow model, a DC approximation, and a transport model should be included. The results need be analyzed to identify fundamental limitations of each model and suggest future research needs.
Measures of Success	Consensus on which types of models are appropriate for assessing various aspects of transmission planning. Recognition and acceptance of limitations associated with reliance on common approaches. Agreement on needed future research to address outstanding issues.
Required Effort	The required effort for a comparative assessment of a benchmark model with the different existing tools should be relatively modest.

Title	**4.3 Uncertainty Analysis and Techniques**
Objective	To develop techniques to extend uncertainty analysis in transmission planning to support the CAISO TEAM framework.
Need	Transmission planning involves analyzing projections of possible future electric-power systems. This is accomplished by considering different scenarios that may represent low resource availability, high resource availability, and a range in between. The scenarios are carefully chosen to represent relevant and possible outcomes and sensitivities about these outcomes. For example, a “low hydro” scenario can be investigated along with the sensitivity to the low hydro assumption. Best and worse cases are normally investigated, and it would be ideal to investigate the whole range of possible future conditions, weighting outcomes by probability. However, this is not possible with a small number of scenarios. A Monte Carlo simulation would be useful, except that the many dimensions of the problem mean that a Monte Carlo simulation would be extremely computationally intensive. Research is needed to develop an uncertainty framework that addresses a comprehensive range of scenarios as well as techniques for efficiently evaluating the model. The result could be a probability distribution of expected benefits from transmission expansion.
“Users”	PTO and regional transmission planners, CAISO, and government agencies
Challenges and Considerations	The technical challenges lie in developing the uncertainty model, specifically defining the range of possible conditions and their relative probabilities, structuring the model(s) to treat uncertainties consistently (e.g., for key drivers such as weather, macro-economic conditions) and developing an efficient algorithm to perform the analysis. New methods may be required to capture the “insurance value” of transmission as a hedge against the effects of certain classes of uncertainties/contingencies.
Possible Approaches	Examine the use of traditional and novel techniques for speeding up Monte Carlo simulations of a detailed engineering model. Alternatively, look into the development of approximate models that are amenable to Monte Carlo simulation. Examine methods that capture the “insurance value” of

	transmission against unforeseen contingencies.
Measures of Success	Greater acceptance of the value and usefulness of uncertainty analysis in transmission planning processes. Use of a distribution of expected benefits within the CAISO evaluation and other transmission expansion decision-making processes
Required Effort	A moderate effort is required to compare alternative approaches and demonstrate their effectiveness. Additional effort will be required for characterizing uncertainties with available data and to develop appropriate model structures that represent key sources of uncertainty consistently.

Title	**4.4 Economic Modeling and Evaluation of "Seams"**
Objective	To improve the accuracy of economic analysis by better characterizing the costs of trade across market seams
Need	In California, trade within the CAISO market is expected to be transparent. Trade across seams between California and the rest of the West will not be transparent for purposes of economic analysis. Because California is a large importer of power, there is a need to characterize the costs of these out-of-market trades in future studies. Other studies note the inherent inefficiencies in transaction and opportunity costs in bilateral markets. To approximate the effect of these inefficiencies in studies that evaluate the benefits of various market designs, a "hurdle rate" rate is applied to generation from outside the market. Hurdle rates vary significantly from 3$/MWh to $15/MWh,[42] but there is little detailed justification for these numbers. Because these amounts affect the outcomes of studies, research is needed to establish and justify the hurdle rates or to develop a different model to account for trade across seams.
"Users"	PTO and regional transmission planners, CAISO, and others who perform economic analyses
Challenges and Considerations	There may not be many data with which to perform an empirical study of the cost of trade across seams. This type of trade is not transparent, and hurdle rates are only one way to try to capture bilateral market inefficiencies. FERC maintains a database of electricity sales from entities under its jurisdiction. The database is relatively new and still under development, but it might be possible to study this database to gain insight into effective costs for sales across market seams, by means of comparisons to similar sales that do not cross seams.
Possible Approaches	An empirical analysis of energy sales could be attempted using FERC electricity quarterly reports or similar sources. Other approaches could include a theoretical study of the causes and effects of seams.
Measures of Success	An accepted method for representing the costs of transactions across seams that is incorporated in the CAISO evaluation

[42] See, for example: U.S. Department of Energy. 2003. *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Design*. DOE/S-0138.

	methodology
Required Effort	A moderate effort will be required to gather and evaluate data, if enough relevant data can be found. A more significant effort would be required to pursue a pure theoretical study.

Title	**4.5 Multi-scale Models**
Objective	To examine tradeoffs and explore options for coordinating among different tools and approaches, each of varying granularity, with the intention of reconciling selection of tool/approach and inherent uncertainty in data
Need	Modeling tools are needed that take better account of the data available to support their use. For example, in the transmission-planning context, long-term regional resource forecasts do not match the detailed bus-level information that is used in detailed engineering studies. In addition to seeking ways to estimate bus-level forecasts from regional forecasts (see next research activity), we need to consider other tools and approaches that will evaluate the data in their most accurate form. Research is needed to evaluate how well simplified models can support long-term planning objectives. Existing models will have to be found or new models developed on which to base long-term decisions. Recognizing that the models must be inaccurate to some degree and that their results will affect decisions made today, there must be some level of confidence that only relatively small adjustments to a long-term transmission plan will be necessary to maintain the integrity of the grid moving forward.
"Users"	Regional transmission planners and stakeholders in the transmission planning process
Challenges and Considerations	Most engineers believe that only detailed models suffice for transmission planning. Therefore we must recognize that this modeling exercise is bound to be challenging. But we must also recognize that long-term forecasted data are not available at a detailed engineering level, and generating such data adds new sources of uncertainty into the planning process. Using a less-detailed, approximate model may introduce less uncertainty than would result from disaggregating forecasts.
Possible Approaches	Apply engineering-based aggregation methods to develop a family of multi-scale models whose resolution will depend on the source and resolution of input data. Alternatively, very simple production-cost-based transport models should be considered for very long-term projected analysis, at least for comparison purposes.
Measures of Success	Development and acceptance of a class of models for long-term planning that use the best regional-level forecasts
Required Effort	A moderate effort is required to examine opportunities to develop multi-scale model. Additional, lesser effort is needed to perform benchmark comparisons between models.

Title	**4.6 Formal Integration of Bus-Level Forecasting with System-Level Load Forecasting**
Objective	To reconcile local bus-level forecasts with system level forecasts
Need	Traditional detailed engineering tools for system analysis require input data at the bus level. Such data may be available or inferred for short term studies but are not generally available from long-term forecasts. If we are to use the most detailed engineering models for our analyses, then disaggregation of regional forecasts to the bus level will be required. Tools to perform this disaggregation are needed as is characterization of the uncertainty entailed in the disaggregation process.
"Users"	PTO transmission planners, CAISO
Challenges and Considerations	Although it is not entirely clear that this is the best approach for addressing long-term forecasts, this bus-level forecast approach may be needed because tools that require it already exist for engineering analysis. If credible bus-level forecasts can be made, then this approach is attractive. If research shows that credible bus-level forecasts cannot be made, other alternatives must be considered. Establishing the credibility and consistency of the forecasts may take time.
Possible Approaches	Project from historical analysis. Integrate local economic planning projections
Measures of Success	Acceptance and use of internally consistent bus-level forecasts by regional transmission planners
Required Effort	A significant effort is required to determine how to develop internally consistent long-term bus-level forecasts and to demonstrate their accuracy

Title	**4.7 Longer-Term Scenario Analysis**
Objective	To develop and organize information to better support long-term scenario analyses than is currently possible
Need	To properly value a transmission-enhancement project we should consider its value over its entire operating lifetime. This may be as long as 40 years or perhaps longer if one considers the value of securing a transmission corridor for continued use. Current studies do not consider the entire lives of projects, expecting a short-term payback. This may be short sighted. An additional reason for long-term scenario development is that it allows policy makers to set energy objectives. Where does the state want to be in 20, 30, and 50 years? Clear objectives may direct energy development. Scenarios, to be realistic, should be based on consistent examination of historic records, among other things.
"Users"	Long-term scenarios will be developed and used by policy makers, transmission planners, and CAISO.
Challenges and Considerations	Reasons for uncertainty in very long-term forecasts are obvious. Accounting for uncertainty while evaluating transmission plans will be a valuable accomplishment.
Possible Approaches	Insight will be gained from consistent review and integration of historical records and evaluation of resources both within and outside California.
Measures of Success	Acceptance and use of long-term scenarios in policy making and transmission-planning evaluation
Required Effort	This activity will require moderate up-front effort and will likely require ongoing development.

Title	**4.8 Generation Adequacy Forecasting**
Objective	To provide long-term forecasts of generation adequacy that are consistent with transmission studies
Need	Long-term studies require estimates of both load needs and generation resources. Analyses of generation and transmission resources are currently not done in a consistent manner. They need to be checked for consistency and reconciled if very different.
“Users”	PTO transmission planners, CAISO
Challenges and Considerations	Currently, specific generation forecasts are based on upcoming plant requests, future load forecasts, and assumptions about the transmission system. Determination of future transmission needs depends on future load forecasts and assumed generation resources. Typically, generation and transmission assessments are not conducted simultaneously and are therefore are not consistent with each other. Market simulation tools do not yet focus on market entry/exit decisions for generation.
Possible Approaches	A number of self-consistent methods may exist that approach an integrated resource planning platform. Or a simple check for consistency of the independent results with a means to adjust for correlations may be sufficient.
Measures of Success	Introduction of a policy to check for consistency and acceptance of a tool to reconcile differences
Required Effort	A small effort is required to check for consistency, but a moderate effort may be required to reconcile differences. Both technical and institutional issues may need to be addressed.

Title	**4.9 Demand-side Alternatives to Transmission**
Objective	Improve consideration of demand-side alternatives in transmission-planning activities
Need	Transmission planning has traditionally been conducted to connect new or planned generation to expected load. There is now greater uncertainty than in the past in siting for new generation, and uncertainty in load is affected by options for energy efficiency, demand response, and distributed generation. We need to consider both when and how to address these demand-side options in the transmission-planning process. Research in this area would focus on addressing the question of how.
"Users"	Utilities involved in resource procurement are the principal users; those more directly involved in transmission planning would be "downstream" beneficiaries/users/recipients.
Challenges and Considerations	Technical and institutional challenges: 1. Information is lacking on market adoption of demand-side options, in particular, on the response to explicit strategies to accelerate their market adoption. 2. For distributed generation, the key market driver – electricity tariff design (e.g., stand-by charges) – is in flux at CPUC. 3. Information on market adoption of demand-side options should, ideally, be available on a geographic basis. 4. There remains significant mistrust (based on lack of experience) of the "hardness" of demand-side options, so they are discounted in the planning process. 5. Procedurally, transmission planning will tend to follow the resource acquisition decisions that would involve consideration of demand-side resources.
Possible Approaches	Current DSM evaluation/planning processes at California IOUs could be modified to explicitly consider market penetration drivers and location-specific targeting. However, these processes have not historically focused on either demand response or distributed generation. Focus on these issues is needed to build the information base required to effectively characterize the resource (this activity is related to the earlier discussion of bus-level forecasting). Methods for integrating demand-side options into resource procurement and planning activities will need to be modified to ensure that location-specific impacts of demand-side interventions are made explicit, so they can be reflected later in transmission planning.

Measures of Success	Explicit representation of the role of demand-side options as well as a discussion of tradeoffs considered in promulgation of transmission plan
Required Effort	Developing the market-adoption and geographic information required is a very large undertaking; likely outside the scope of PIER Transmission. Examining ways that current planning tools/processes might incorporate this information is likely a modest effort, given the assumption that it will be some time before the foregoing data needs are adequately addressed (hence, very crude approaches will have to suffice for a period of time; these would warrant only very simple modifications to existing approaches).

Title	**4.10 Integration of Natural Gas Pipeline and Electricity Transmission Planning**
Objective	To develop models and tools that simultaneously consider planning for natural gas pipelines and electricity transmission lines
Need	Natural gas pipelines and electricity transmission lines may serve as substitutes for one another in some areas. A locally sited generator served by a natural gas pipeline may obviate the need for transmission expansion to access generation from a more remote location.
"Users"	Regional transmission planners and local stakeholders seeking to consider all available options
Challenges and Considerations	Model enhancement to include both gas pipelines and transmission lines will require data collection. It will also require efforts external to these models to integrate outputs/inputs among them and to ensure consistency in the base data used to drive them. Integrated tools may be required to aid in assessing the long-term tradeoff between a pipeline and a transmission line.
Possible Approaches	Develop enhanced algorithms to perform multiple scenario analyses to evaluate gas/electricity options simultaneously
Measures of Success	Acceptance and use of models and tools by regional planners and stakeholders
Required Effort	Moderate effort will be required to develop models and tools.

Title	**4.11 Macro-Economic Studies**
Objective	To assess impact of transmission expansion on economic growth and property values, as well to determine the economic value of reliability to customers.
Need	Transmission expansion has impacts beyond those considered in engineering analyses. New lines affect nearby property values and arguably spur economic growth. Quantification of these effects will be valuable for stakeholders engaged in transmission-planning process. The value of the reliability benefits associated with transmission and non-transmission activities derives ultimately from the value that customers place on reliability. These data are not collected routinely, nor have they been collected with an eye toward using them to support transmission planning activities. Utilities have conducted macroeconomic studies in the past. Updated studies performed by CEC would be valuable for today's stakeholders.
"Users"	Stakeholders engaged in the transmission planning process
Challenges and Considerations	It is important that these studies be conducted by an organization that is independent of the stakeholder process, to avoid any appearance of a conflict of interest. There should be sufficient data with which to conduct these studies; however, there have been so few major transmission projects in recent years that due consideration will need be given to interpret historical data in the present-day environment.
Possible Approaches	Evaluate data and seek correlations form transmission line construction to property values and to economic growth Conduct or direct preparation of value-of-services studies (potentially in coordination with CPUC)
Measures of Success	Introduction of findings from these studies into the planning process by stakeholders
Required Effort	A low level effort will be required to gather and analyze relevant data. Primary survey research (e.g., customer value of service surveys) requires more effort.

Title	**4.12 Common Regional Databases and Information Exchange**
Objective	To develop an open transmission-planning data-management framework for collecting, maintaining, and disseminating relevant regional data models
Need	Virtual representations (models) of transmission-level power system networks and corresponding economic market models are required for analysis of planning issues. Open formats are needed for data collection and retrieval so that tools supplied by multiple vendors, research institutions, and other parties can be chosen by information users. Merging and dissecting portions of models are needed to support subregional interests or subareas of concentrated study. Security mechanisms are needed to protect sensitive business data and national security interests.
“Users”	PTO and subregional planners (NTAC, RMATS, STEP, etc.), as well as western regional planning groups (SSG-WI, Planning WG)
Challenges and Considerations	Ensuring consistency among data developed originally by different parties (often, to support different objectives) is a significant challenge. Data models are exchanged today in proprietary formats and converted to competing formats by the users of the information. Users acknowledge the deficiencies of the present system; vendors need to be brought into the process and participate in solution approaches. All parties must work together for success to be possible. Ideas must come from all sectors, but researchers can focus to issues, propose alternatives, and articulate potential approaches.
Possible Approaches	Analyze the mechanisms used today to exchange information, create regional information models, and disseminate information to users; Facilitate workshops sponsored by stakeholders in regional planning (e.g., CREPC or SSG-WI) to define issues and consider approaches; Help connect existing information exchange format initiatives (e.g., IEC 61970) to transmission-planning needs and establish a standardization forum for gathering stakeholders around an agreeable approach and solidifying its definition. Throughout this process, coordination of existing modeling efforts would be supported to facilitate transition to an improved regional data/model-maintenance framework.
Measures of Success	Definition of a regional model-management framework, a commonly held format for information exchange, and

	coordination among related regional/subregional groups
Required Effort	The research activity would contribute in the early stages of the process, in concert with leadership from respected stakeholder contributors. Once an initiative is set in motion and direction is determined, the need for research support would diminish as the efforts of those involved in implementation and on-going maintenance increases.

Title	**4.13 Transmission-Corridor Planning/Assessment Tools**
Objective	To improve stakeholder (including public) access to consistent and comprehensive information on all impacts associated with transmission-line siting; facilitate comparison and consideration of alternative siting paths.
Need	Siting transmission lines is politically contentious, in part because the process must accommodate significant public input. Current processes often flounder for (at least) two reasons: 1) alternatives are suggested "too late" in the process because current processes focus on mitigation for a specific proposed route, not a broader consideration of potential alternatives; and 2) information on the impacts of a potential route is neither readily available nor comprehensive, so different parties base their participation in processes on limited, inconsistent, or incorrect information.
"Users"	Participants/stakeholders in transmission-line route planning and siting processes, including state/federal/regional/local agencies, utilities/ISOs, generators, customer groups, local organizations, and environmental groups
Challenges and Considerations	Technical and institutional challenges: 1. Limited resources of participants, which means participation may be selective or targeted to specific issues to exclusion of other issues 2. Incomplete data on impacts of various proposed projects including the data necessary to ascertain these impacts (e.g., geographic-based land use, habitat, and demographic forecasts, in addition to the incorporation of existing or commissioned results from survey research, and econometric studies). 3. Distrust of data sources (e.g., utility sources perceived to have conflict of interest) 4. Incomplete/inaccurate understanding of costs and benefits and how specific constituencies are affected 5. Distrust of process/forum shopping (e.g., sand-bagging until the California Environmental Quality Act (CEQA) review)
Possible Approaches	The Resources Agency's California Conservation Digital Atlas has integrated a large number of GIS databases on aspects of land use. This large database could be enhanced to support transmission-corridor planning and include information on habitat, demographic forecasts, and terrain constraints. SCE has worked with a private firm to develop a web-based tool for representing impacts of transmission projects for

	internal use by SCE staff. This tool could be enhanced to facilitate broad stakeholder access to common information on impacts of transmission-line routing alternatives. EPRI has work with Southern Co. to develop an "optimal" transmission line route-finding tool. This tool could be modified for application in California.
Measures of Success	The principle measure of success is improved transmission line siting. Indicators would include greater consensus on identified corridors for future transmission and faster review and approval for specific transmission lines.
Required Effort	The technical challenges facing work in this area and the resources required are modest. The institutional challenge – stronger leadership in the state for transmission – is significant. R&D can support but will never replace the need for this leadership.

Title	**4.14 Probabilistic vs. Deterministic Reliability Criteria**
Objective	To develop techniques for a probabilistic assessment of reliability
Need	Current reliability assessment is limited by available tools. The standard, deterministic N-1 criterion dictates that the system must be able to withstand any single event, which makes a calculation of reliability feasible. Consideration of multiple events is a combinatorial process that is not generally possible even with fast computers. However, it is well known that some multiple contingency events are more probable than some single contingency events, and the impact of many single contingencies is negligible. An approach could be considered in which both the probability and impact of events can be addressed to evaluate system reliability. Thus, certain low-probability, very high-impact events may require as much, or more, attention than many high-probability but lower-impact events. This probabilistic approach should also quantify the economic impact of reliability. A practical technique for sorting events by probability-weighted impact is needed for a probabilistic approach.
"Users"	Grid operators, transmission planners, and others who account for reliability in their studies
Challenges and Considerations	Enumerating multiple contingencies is combinatorial and beyond present computational power. A different approach is required. Also, probabilities of events are not well established, and consistent, accepted data would need to be used. If a practical probabilistic approach is established, approval from reliability councils will be required to make the approach standard.
Possible Approaches	Reverse the present approach: instead of asking whether the system is secure subject to a list of events (N-1), ask for which events will the system be insecure. A technique that can identify high-impact events without enumeration will make this approach possible.
Measures of Success	Acceptance of a probabilistic reliability criterion
Required Effort	There are no known, proven techniques that automatically identify important events based on probability and impact. Significant effort will be required to research such a technique.

Title	**4.15 Voltage/Reactive Reserve Modeling**
Objective	To develop advanced simulation tools that capture voltage instability better than is currently possible, with the purpose of improving voltage reliability criteria.
Need	Present voltage reliability requirements are insufficient to capture instances of voltage instability. A grid event is considered secure, from a voltage point of view, if the power flow converges. This criterion does not entail checking to ensure that voltages remain within an acceptable operating range, and it does not take system dynamics into account. There is a gap in stability analysis between generator dynamics (a few seconds) and steady state (several minutes). Within this gap, network components actuate that depend on or affect voltages. Advanced simulation techniques are required to capture these dynamic effects to ensure the system is safe from voltage instabilities.
"Users"	Grid operators, CAISO, and PTO and regional transmission planners who need to account for system reliability in their studies
Challenges and Considerations	There are challenges in developing models for all components that may affect the outcome of a simulation, especially flexible AC transmission (FACTS) devices. The greatest challenge will be the development of fast algorithms which with to conduct the simulations. One of the reasons traditional stability studies stop after a few seconds is the computational burden of analyzing longer time periods.
Possible Approaches	There are numerous approaches to this problem including faster simulation algorithms, adaptive multi-scale models that decouple fast and slow dynamics, and "energy function" methods to refine reactive power margins for voltage stability.
Measures of Success	Development of tools to accurately assess voltage stability criteria and acceptance of new reliability standards and operating procedures that incorporate these tools
Required Effort	A significant effort will be required to develop and prove new tools and to gain acceptance for them as part of a new reliability standard.

Title	**4.16 Load Modeling**
Objective	To account for load-model uncertainties in reliability studies
Need	The demand/voltage and demand/frequency characteristics of aggregate loads are not well known. Studies of outages have shown that these features are not well represented in our base-case models. Furthermore, these characteristics are known to have a significant impact in severe cases – the types of limiting cases that we study for reliability. There is a need to understand these load-model characteristics if possible, or, if this is not possible, then it is appropriate to assess the uncertainty in these models as employed in reliability studies.
"Users"	Transmission planners and others who evaluate system reliability
Challenges and Considerations	An empirical analysis is difficult. Direct testing on the power grid is not feasible because we do not want to create the drastic conditions that reliability planning seeks to avoid. Attempts to construct a high-level aggregate model from physical models of individual components are necessarily approximate and introduce uncertainties. On positive note, data for many devices appear in the literature.
Possible Approaches	Seek ideas for empirical approaches. Develop approximate models and tools to directly assess the impact of uncertainty.
Measures of Success	Acceptance and use of new tools to characterize loads and assess the impact of uncertainty in reliability studies
Required Effort	A moderate effort is required to develop models and parameters suitable for uncertainty analysis.

Title	**4.17 Deliverability Assessment**
Objective	To develop a tool to quickly assess the deliverability capability of a generating unit
Need	Deliverability is becoming a key issue in the California market. Policies in other ISOs require that load-serving entities procure enough deliverable energy to meet their needs, including reserves. Polices also dictate that new generation facilities must meet some deliverability requirements and may have to pay for upgrades to the transmission grid, beyond connection costs, to meet the deliverability requirements. The application of deliverability requirements will be facilitated by the development of a tool to quickly calculate the deliverability of specified generation and loads, and to evaluate options for transmission upgrades to meet deliverability requirements. A geographically-based tool would be effective that outlines the effective deliverability area of a select generator or highlight the deliverable resources for select loads as needed.
"Users"	Generating facilities and CAISO for interconnection studies, and transmission planners, CAISO, and others involved in transmission upgrade approvals
Challenges and Considerations	Other ISOs already have deliverability policies and perform deliverability assessments. Traditional tools can be adapted for this purpose, or specialized tools could be developed. Standard power-flow tools coupled with some visualization tools and some directed software may be enough to develop this tool. A brute-force approach, involving many load flows, will be computationally burdensome; a fast technique that might be refined by a few power flows would be welcome. Availability and use of a common database (consisting of other expected new generation and transmission lines) would facilitate these studies.
Possible Approaches	The deliverability between a generator/load pair can be calculated by repeated power flows. However, this approach is inefficient because of the large number of generator/load pairs. An approximation could help define an initial deliverability area, which can be refined by full power flows.
Measures of Success	Development of a tool that quickly determines the deliverability area of a resource; this may be applied by CAISO in operations and by most stakeholders in the planning stage.
Required Effort	A moderate effort will be required to develop this tool. At the core, such a tool must rely on well-known power-flow and

	related tools. Effort will be spent on customization to address deliverability assessments and, possibly, visualization techniques.

Appendix A. Interviews Conducted by the Project Study Team

CEC Staff – 9 Feb 2004

Permitting/Siting – M. Hesters, D. Bucaneg (email), D. Kondoleon

Electricity Office – D. Aushuckian, J. Klein, D. Vidaver, A. Tanghetti, A. Belostotsky

PIER Environment – K. Birkenshaw, L. Spiegel

PIER Renewables - G. Simon, E. Sison-Lebrilla

CAISO – 24 Feb 2004

Transmission Planning – Armie Perez

Dept. of Market Analysis – Anjali Sheffrin, Keith Casey, Eric Hildebrandt

WAPA – 24 Feb 2004

Transmission Planning - Morteza Sabet, Kirk Sornborger

SCE – 25 Feb 2004

Transmission Planning – Pat Arons, Mary Deming, Tony Velarde (18 Feb)

Pacific Northwest – 1-3 Mar 2004

BPA – Dennis Phillips, Ottie Nelson, Brian Silverstein, et. al.
OR DOE – Phil Carver
NWPPC – Wally Gibson

SDGE – 5 Mar 2004

Transmission Planning – Dave Korinek, Abbas Abed, Dave Wang

PG&E – 17 Mar 2004

Transmission Planning – Kevin Dasso

LADWP – 31 Mar 2004

Transmission Planning – Tim Wu

CEC Staff – 20 Apr 2004

Sr. Policy Advisor – Grace Anderson

Risk Team – Kay Lewis, Sy Goldstone, Nahid Movassagh, Clare Laufenberg, Miguel Cerrutti, Jairam Gopal

CPUC – 18 May 2004

Strategic Planning – Barbara Hale, Kerry Hattevik, Maryam Ebke

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